TECHNICAL REVIEW AND EVALUATION

BOWIE POWER STATION, L.L.C.

AIR QUALITY PERMIT NUMBER 34918

I. INTRODUCTION

This Class I (Title V) Permit is for the installation and operation of the Bowie Power Station (Bowie), which will be located approximately two miles north of the unincorporated community of Bowie, in Cochise County, Arizona. This is a new "merchant" power plant project that will generate and sell electricity produced by natural gas combustion. The application was submitted on December 22, 2004.

Bowie Power Station, L.L.C. was initially issued a Class I operating permit on March 26, 2003. This original PSD permit imposed a BACT limit of 2.5 ppmvd on a 1-hour average for NO_x. This original permit was terminated on September 26, 2004, upon expiration of the 18 month construction timeframe under Arizona Administrative Code (A.A.C.) R18-2-402.D.

This Permit imposes a NO_x Best Available Control Technology (BACT) limit of 2.0 ppmvd at 15% O_2 on a 3-hour averaging time. In addition to imposing a more stringent BACT limit, this permit also requires that the averaging time be reduced to 1-hour after an 18-month demonstration period, unless the Permittee can use data collected in this period to show that a limit of 2.0 ppmvd cannot be achieved on a 1-hour average despite proper maintenance and operation of the SCR system.

A. Company Information

Facility Name: Bowie Power Station, L.L.C.

Mailing Address: 4350 East Camelback Road, Suite B150
Phoenix, AZ 85018

B. Attainment Classification

The proposed source is to be located in an area that is designated attainment/unclassified for all criteria pollutants: total suspended particulate (TSP), particulate matter less than 10 microns in diameter (PM_{10}), nitrogen dioxide (NO_2), sulfur dioxide (SO_2), carbon monoxide (CO), lead (Pb), and ozone (O_3).

II. PROCESS DESCRIPTION

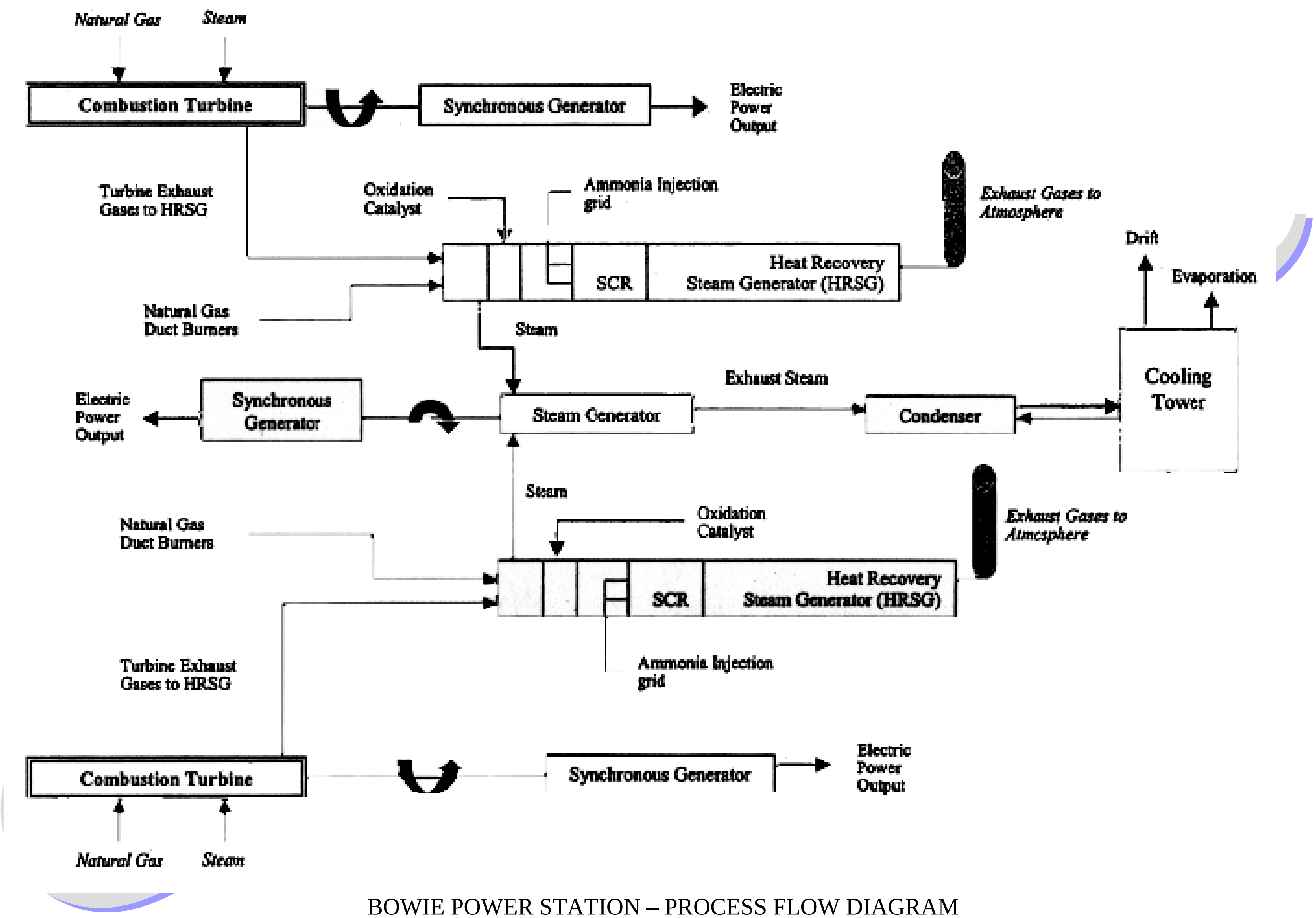
The Bowie Power Station Project is a natural gas fired combined cycle merchant power plant with a total site rating of 1,050 Megawatts (MW) (nominal). The facility will consist of four combustion turbine generators (CTG), four heat recovery steam generators (HRSG) with supplemental firing, two steam turbine generators (STG), and two mechanical draft cooling towers. Auxiliary equipment include a natural gas-fired boiler, two diesel-fired standby generators, and two diesel-fired emergency fire pumps. Only natural gas fuel will be used for the combined cycle units.

The project is classified as Standard Industrial Classification Code 4911 and North American Industrial Classification System 221112, Fossil-Fuel Electric Power Generation. The primary processes at this facility consist of the following equipment:

- Four (4) General Electric 7FA CTGs equipped with dry low-nitrogen oxide (low-NO_x) combustors;
- Four (4) HRSGs with supplemental duct firing at a rated heat capacity of 420 million British Thermal Units per hour (MMBtu/hr) (higher heating value (HHV));
- Two (2) STG units;
- Four (4) selective catalytic reduction (SCR) systems for controlling nitrogen oxide (NO_x); and
- Four (4) oxidation catalyst systems for controlling CO and volatile organic compounds (VOCs).

The support processes at this facility will consist of the following equipment:

- One (1) 50 MMBtu/hr natural gas-fired auxiliary boiler equipped with low-NO_x burners;
- Two (2) 12-cell wet mechanical draft cooling towers equipped with high efficiency drift eliminators for steam turbine condenser and equipment cooling;
- Two (2) 8.4 MMBtu/hr diesel-fueled emergency generators;
- Two (2) 260 horsepower (hp) diesel-fueled engines to drive the emergency fire water pumps;
- Main transformers; and
- Other ancillary equipment.



BOWIE POWER STATION – PROCESS FLOW DIAGRAM
From Figure 2-4 of Class I Application submitted February 15, 2002

The combustion turbine compresses chilled air which is mixed with natural gas and burned in the dry low-NO_x combustors. The resulting high temperature gases pass through the power turbine and exhaust to the HRSGs. The power turbine drives both the compressor and an electrical generator. The generators on each CTG are capable of producing 172 MW (nominal). Each operating unit will be configured such that steam can be injected into the combustion turbine between the combustor and the first stage turbine to increase mass flow. This increased mass flow results in increased power production and is referred to as power augmentation. The turbine exhaust gases are treated with an SCR system and an oxidation catalyst to further control NO_x, CO, and VOC emissions before being exhausted to the atmosphere.

The HRSGs are boilers that generate steam from the heat in the CTG exhaust gases. To increase overall output from the facility, supplemental (duct) firing of the HRSGs using natural gas may be performed so that additional steam can be produced for the STG. The STGs are capable of generating 180 MW each. Because the STGs do not combust fuel, there are no air emissions from these units.

Low pressure, low temperature steam exhausted from the STG is condensed in the main condenser. The condensate is recycled for use in generating more steam. The condenser is cooled by the circulating water system that rejects waste heat to the atmosphere by evaporation in the cooling towers.

III. EMISSIONS

Tables 1 through 4 present the proposed short-term and annual emission limits for the units. The proposed permit limits are based on vendor and applicant data, and the application of control devices selected through the Best Available Control Technology (BACT) analysis.

A. Normal Operations - Hourly Emission Rates

Table 1 lists the combined cycle system maximum hourly emission rates under any combination of full load operation and ambient temperatures. Table 1 also includes emissions with duct firing and power augmentation, duct firing only, and neither duct firing nor power augmentation. Duct firing and power augmentation are to occur only after a combustion turbine has reached 100 percent load.

Table 1. Hourly Emission Limits During Periods Other than Start-up or Shutdown

Device	Hourly Emissions, Each CTG/HRSG, pound per hour (lb/hr)				
	NO_x	CO	VOC	PM_{10}	SO_2
Combined Cycle Systems, Duct Firing + Power Augmentation	**15.4**	**13.1**	**9.5**	**22.0**	**8.7**
Combined Cycle Systems, Duct Firing	**12.6**	**7.6**	**4.4**	**18.3**	**8.7**
Combined Cycle Systems	**12.0**	**4.1**	**2.0**	**15.0**	**5.7**

Notes:

1. The Combined Cycle Systems consist of one combustion turbine, one heat recovery steam generator with its associated duct burner, post combustion emission control systems, and exhaust stack.
2. PM_{10} emission rate includes condensable and filterable components.
3. Normal operation for the turbines are defined as loads above or equal to 50% of nameplate capacity, and start-up/shutdown are defined as loads below 50% of nameplate capacity.
4. Duct burning is limited to a 41% capacity factor (1471 mmscf/year fuel usage) for each Combined Cycle System and power augmentation is limited to 1,000 hours per year for each Combined Cycle System.

B. Start-up/Shutdown Operations - Hourly Emission Rates

Emissions of NO_x, CO, and VOCs from the combustion turbines during start-up/shutdown are significantly higher than during steady-state, full load operation. This is because combustion temperatures and pressures are rapidly changing during start-up/shutdown (which results in less efficient combustion and higher emissions), and because the dry low-NO_x combustors are operating in diffusion mode, not dry low-NO_x mode. In addition, pollution control systems such as oxidation catalysts are not as effective during the transitory temperature changes that occur during start-up/shutdown.

The higher NO_x, CO, and VOC start-up/shutdown emission rates must be included in the annual potential to emit (PTE) calculations, and are also considered in the air quality modeling analyses. The only pollutant that requires a separate start-up/shutdown short-term modeling analysis is CO, because it is the only one of these three pollutants with short-term air quality standards. For NO_x, the air quality standard is an annual standard, therefore the annual NO_x emission rate that is modeled must include total emissions from both normal operations and start-up/shutdown operations. Because of the CO and NO_x modeling requirements to demonstrate compliance with air quality standards and increments, separate start-up/shutdown emission limits have been established for CO and NO_x and are listed in Table 2. Compliance with the start-up/shutdown CO and NO_x emission limits in Table 2 shall be determined using continuous emissions monitoring systems (CEMS).

Table 2. Hourly Emission Limits During Periods of Start-up or Shutdown

Device	Hourly Emissions, Each CTG/HRSG, lb/hr	
	NO_x	CO
Combined Cycle Systems	102.4	250.0

Notes:

1. Start-up is defined as the period between initiation of fuel flow until the electrical load of the Combustion Turbine increases to 50% or more of the nameplate capacity.
2. Shutdown is defined as the period beginning when the electrical load of a Combustion Turbine drops below 50% of nameplate capacity and ending when fuel flow has ceased.
3. Combined hours in both start-up and shutdown mode for each Combined Cycle System is limited to 733 hours per year.

Even though VOC emissions are higher during start-up/shutdown operations (and these higher emission estimates are included in the annual VOC emission calculations), it is not practical to establish VOC start-up/shutdown emission limits because of the difficulty in testing for compliance (U.S. Environmental Protection Agency (EPA) Reference Methods 25A and 18 manual stack tests are used for VOCs, which are very difficult to conduct during the non-steady-state conditions of start-up/shutdown). In addition, a start-up/shutdown modeling analysis is not required for VOCs (there are no air quality standards for VOCs and the relationship between hourly VOC emission rates and ambient ozone concentrations is extremely difficult to determine). Therefore, separate VOC start-up/shutdown emission limits have not been established.

Because emissions of particulate matter (PM/PM_{10}) and SO_2 do not increase during start-up/shutdown, separate start-up/shutdown emission limits are not established for these pollutants.

C. Annual Allowable Emission Limits

Table 3 presents the maximum annual facility PTE considering all permitted sources. Annual operations will be limited by the specific limits on hours of operation for the various operating modes (normal, power augmentation, duct firing, and start-up/shutdown). The total allowable emissions in Table 3 include emissions from the proposed auxiliary boiler, emergency generators, and fire pump engines, all of which include limits on hours of operation per year.

Table 3. Average Annual Emissions

Device	Average Annual Emissions, TPY				
	2.0 ppm[1] NO_x	**CO**	**VOC**	**PM10**	**SO2**
Combined Cycle System 1	64.2	73.9	21.6	74.0	30.4
Combined Cycle System 2	64.2	73.9	21.6	74.0	30.4
Combined Cycle System 3	64.2	73.9	21.6	74.0	30.4
Combined Cycle System 4	64.2	73.9	21.6	74.0	30.4
Auxiliary Boiler	0.55	0.93	0.06	0.08	0.007
Cooling Towers (2)	N/A	N/A	1.6	20.95	N/A
Diesel Emergency Generators (2)	3.23	0.86	0.09	0.06	0.05
Diesel Fire Water Pump Engines (2)	0.96	0.21	0.08	0.07	0.01
TOTAL	**261.2**	297.6	88.3	317.0	121.6

Note:
1. 2.0 ppmvd@15% O_2
2. The combined cycle systems will be controlled using dry low-NO_x combustors, SCR, and an oxidation catalyst
3. The auxiliary boiler will be controlled using low-NOx burners.

At full load and 59 degrees Fahrenheit (°F) (the annual average temperature at the site) the heat input of the combustion turbines will be 1,680 MMBtu/hr, and for the duct burners 420 MMBtu/hr (HHV). Normal operation is defined by the applicant at loads above or equal to 50%. The applicant calculated emissions for the combined cycle units during operation at 100% load using 8,027 hours per year, including a 41% capacity factor for duct firing (1471 mmscf/year fuel usage) and 1,000 hours per year for power augmentation.

Start-up/shutdown for the turbines are defined as loads below 50%. The amount of time a unit has been shutdown will determine whether the subsequent start-up is hot, warm, or cold. According to information from the turbine manufacturer, a hot start-up occurs if a unit has been offline for less than 8 hours, a warm start-up if it has been offline between 8 and 72 hours, and a cold start-up if it has been offline for greater than 72 hours. The applicant calculated start-up/shutdown emissions based on 65 cold starts and 220 warm starts, and 285 shutdowns per year. Emissions per start-up and shutdown were provided by the turbine manufacturer. Based on the durations of the various start-ups and shutdowns provided, the annual limit on combined hours in both start-up and shutdown mode for each turbine is 733 hours per year.

D. BACT and New Source Performance Standard (NSPS) Emission Limits

Additional emission limits or concentrations required by regulations (e.g., NSPS, BACT) are shown in Table 4 on the following page. No alternate operating scenarios have been proposed by the applicant.

IV. APPLICABLE REGULATIONS

There are two components to the New Source Review (NSR) permitting program codified in Article 4 of the ADEQ regulations: Prevention of Significant Deterioration (PSD) and Nonattainment NSR. The PSD program is applicable in areas that are attaining air quality standards, or are "unclassified", and it is intended to prevent further deterioration of air quality in the area. Nonattainment NSR applies in areas that are exceeding air quality standards.

In order to trigger the applicability of either of these programs, the source must meet the definition of a major stationary source. As shown in Table 5, the Bowie project is a major source because it is a "categorical source" (as in Arizona Administrative Code (A.A.C.) R18-2-401) with potential emissions of a regulated pollutant above the 100 ton per year (tpy) threshold. Because the proposed location of the Bowie facility is designated attainment/unclassified for all criteria pollutants, only applicability with the PSD permitting program must be evaluated. The PSD applicability significant emission rate thresholds are exceeded at Bowie for NO_x, CO, VOC, SO_2, PM and PM_{10}.

Table 4. Additional BACT and NSPS Emission Limits

Device	Concentration or Rate Limits				
	NO_x	CO	VOC	PM_{10}	SO_2
Each Combustion Turbine Exhaust Operating in Conditions Other than Start-up	Determined by calculation[1]				SO_2 emissions <150 ppmvd or sulfur fuel content of <0.8% by weight[2]
Each Duct Burner Exhaust	1.6 lb/MW-hr[3]	--	--	0.03 lb/MMBtu[4]	0.20 lb/MMBtu[5]
Each Combined Cycle System Exhaust	2.0 ppmvd, 3-hour rolling average[6] (subject to 18 month demonstration period) then reduced to 1-hour	3 ppmvd 50-100% load[6] 3-hour rolling average	2.6 ppmvd 50-100% load[6] 3-hour rolling average	22 lb/hr with power augmentation and duct firing[6,7]	--

[1] Based on NSPS Subpart GG, 40 Code of Federal Regulations (CFR) 60.332(a)(1).
[2] Based on NSPS Subpart GG, 40 CFR 60.333(a).
[3] Based on NSPS Subpart Da, 40 CFR 60.44a(d)(1)
[4] Based on NSPS Subpart Da, 40 CFR 60.42a(a)(1).
[5] Based on NSPS Subpart Da, 40 CFR 60.43a(b)(2).
[6] Limits from BACT.
[7] 18.3 lb/hr with duct firing and 15.0 lb/hr without duct firing and power augmentation.
"--" means that no additional concentration or rate limit is specified for that pollutant.

Notes:

1. Concentration limits are parts per million by volume (ppmvd) corrected to 15% oxygen (O_2) on a dry basis.
2. Parts per million (ppm) emission limit for NO_x is a 1-hour rolling average calculated from continuous monitors. This emission limit may be reduced to 2.0 ppmvd on a 1-hour rolling average after the first two years of operation based on the NO_x demonstration required by the permit.
3. Emission limit for CO is 3-hour rolling average calculated from continuous monitors. VOC and PM_{10} averaging times are consistent with the stack testing methods (three 1-hour averages).
4. Ammonia emissions associated with the SCR control system will be limited to 10 ppmvd on a 24-hour rolling average, this emission limit may be reduced to 7.5 ppmvd on a 24-hour rolling average after the first two years of operation based on the NH_3 demonstration required by the permit.
5. To monitor for compliance with 40 CFR Part 60 Subpart GG, NO_x emissions shall be calculated as required by 40 CFR 60.335(c)(1) unless the Combustion Turbines are installed with a controller programmed with an algorithm acceptable to the Director that continuously corrects for variations in ambient humidity, temperature, and pressure yielding a relatively constant NO_x concentration when corrected to 15 percent oxygen, in which case the continuous emission monitoring data can be used without the 40 CFR 60.335(c)(1) correction.
6. When multiple or alternative limits apply, the most stringent limit governs.

Table 5. Potential to Emit and Applicability Thresholds

Pollutant	Potential Emissions (TPY)	Major Source Threshold (TPY)	Significance Level for PSD (TPY)	PSD Applicable?
NO_x	261.2	100	40	Yes
CO	297.6	100	100	Yes
VOC	88.3	100	40	Yes
PM_{10}	317.0	100	15	Yes
SO_2	121.6	100	40	Yes

The PSD permitting program requirements are contained in A.A.C. R18-2-406 of the ADEQ regulations. The requirements include an analysis of BACT; an ambient air quality impact analysis for increment consumption and National Ambient Air Quality Standards (NAAQS); a visibility and other air quality related values (AQRV) impact analysis for Class I wilderness areas; and an analysis of additional impacts, including growth, soils, vegetation, and visibility impairment.

A. Permitting Requirements

As described above, the proposed facility is a major source for NO_x, CO, VOC, PM_{10}, and SO_2 under the PSD permitting program. The source is also a major source under A.A.C. R18-2-302 of the ADEQ regulations, those implementing the Title V permitting requirements. ADEQ has a unitary permit program so that sources apply for a permit under NSR and Title V concurrently. The permit application submitted by Bowie covers both the PSD and Title V programs.

1. Title V

As a major source for Title V, the proposed Bowie project is required to obtain a Class I (Title V) permit. The permit application and its supplements submitted by Bowie list applicable requirements and contains compliance information, as well as a certification of compliance, which are all required as part of a Title V permit application. Title V includes the specification of appropriate monitoring requirements, and as outlined in Section VI of this document, monitoring provisions are included in the permit.

2. PSD

The facility will have potential emissions above the PSD significance thresholds for NO_x, CO, VOC, PM_{10}, and SO_2. As a PSD major source, the facility is required by A.A.C. R18-2-406 to obtain a PSD permit. As explained in this section, the PSD requirements codified at R18-2-406 are applicable for these pollutants. The requirements include a determination of BACT for NO_x, CO, VOC, PM_{10}, and SO_2, an analysis of the air quality impact of the project, and additional impacts, which are discussed in Sections V and VIII.

B. Other Applicable Requirements

1. New Source Performance Standards (NSPS)

Federal authority for NSPS requirements (delineated in 40 CFR Part 60) has been delegated to ADEQ, and Article 9 of the ADEQ regulations adopted the NSPS by reference. For the proposed project, the combustion turbines are subject to NSPS Subpart GG, the duct burners at the heat recovery steam generators are subject to Subpart Da, and the auxiliary boiler to Subpart Dc.

a. NSPS Subpart GG, Stationary Gas Turbines, is applicable to turbines with heat input capacities greater than 10 MMBtu/hr. In addition to the requirements of Subpart A, General Provisions, the following are the applicable requirements of Subpart GG for the proposed turbines:

i. §60.332, Standard for NO_x, includes an equation to calculate allowable NO_x emissions in parts per million (ppm). From the equation, the nominal NO_x emission rate for the proposed turbines is 75 ppmvd @15% O_2 (without correction for thermal efficiency), which is much higher than the permitted rate.

ii. §60.333, Standard for SO_2, specifies SO_2 emissions <150 ppmvd or a sulfur fuel content of <0.8% by weight. Natural gas is the only fuel that will be combusted by the proposed project and it is inherently low in sulfur. Compliance with this standard will be met by burning only pipeline quality natural gas.

iii. §60.334, Monitoring of Operations, requires monitoring of sulfur and nitrogen content of the fuel being fired in the turbine on a daily basis. A custom schedule for determination of these values may be developed based on the design and operation of the turbines and the characteristics of the fuel supply. The custom schedule shall be substantiated with data and must be approved by the Director before it can be used to comply with §60.334(b).

iv. §60.335, Test Methods and Procedures, specifies the methods to determine the nitrogen and sulfur contents of the fuel, and how to determine compliance with the NO_x and SO_2 standards. Appropriate test methods are also discussed.

b. NSPS Subpart Da, Electric Utility Steam Generating Units, is applicable to duct burners at heat recovery steam generators with heat input capacities greater than 250 MMBtu/hr. In addition to the requirements of Subpart A, General Provisions, the following are the applicable requirements of Subpart Da for the proposed duct burners:

i. §60.42a(a)(1), Standard for PM, specifies that PM not exceed 0.03 lb/MMBtu heat input. §60.42a(b) requires opacity to be < 20% (6-minute average), except for one 6-minute period per hour not exceeding 27%.

ii. §60.43a(b)(2), Standard for SO_2, specifies that SO_2 not exceed 0.20 lb/MMBtu.

iii. For a new source, §60.44a(d)(1) specifies that NO_x (expressed as NO_2) not exceed 1.6 lb/MW-hr gross energy output, based on a 30-day rolling average. Compliance provisions for duct burners subject to §60.44a(d)(1) are specified in §§60.46a(k).

iv. From §60.46a(c), Compliance Provisions, these standards apply at all times except start-up, shutdown, and malfunction.

v. §§60.47a(a) and (b), Emission Monitoring, states a continuous monitoring system (CMS) is not required for opacity or SO_2 if gaseous fuel is the only fuel combusted. As per §60.47a(o) duct burners subject to §§60.44a(a)(1) or (d)(1) do not require the installation of CMS for NO_x; a wattmeter to measure gross electrical output; meters to measure steam flow, temperature, and pressure; or a continuous flow monitoring system.

vi. §§60.48a(b), (c), and (d), Compliance Determination Procedures and Methods, specify the methods to determine compliance for PM, SO_2, and NO_x. Alternative methods are provided in §60.48a(e).

vii. §60.49a(a), Reporting Requirements, requires submittal of initial performance test data for SO_2, NO_x, and PM.

viii. §60.49a(b), Reporting Requirements, specifies the submittal of the information listed for SO_2 and NO_x.

ix. §60.49a(g), Reporting Requirements, requires the submittal of a signed statement regarding the items listed.

x. §60.49a(h), Reporting Requirements, defines excess emissions for opacity and requires quarterly reporting.

xi. §60.49a(i), Reporting Requirements, requires submittal of semiannual reports.

xii. §60.49a(j), Reporting Requirements, states that a source may submit electronic reports in lieu of the written reports required under paragraphs (b) and (h).

c. NSPS Subpart Dc, *Small Industrial-Commercial-Institutional Steam Generating Units*, is applicable to boilers with heat input capacities between 10 and 100 MMBtu/hr. In addition to the requirements of Subpart A, *General Provisions*, the following are the applicable requirements of Subpart Dc for the proposed auxiliary boiler:

i. Note that the SO_2 and PM emission requirements in Subpart Dc only apply to sources combusting coal, oil, or wood. Also, there are no requirements in Subpart Dc for NO_x.

ii. §60.48c(a), Reporting and Recordkeeping Requirements, requires the submittal of notification of the date of construction, anticipated date of start-up, and date of actual start-up.

iii. §60.48c(g), Reporting and Recordkeeping Requirements, requires the submittal of the amounts of fuel combusted each day.

iv. §60.48c(j), Reporting and Recordkeeping Requirements, specifies the reporting period as 6 months.

Because the BACT requirements for Bowie will mandate much lower emission rates than required by NSPS, a permit streamlining analysis is included in Section IV.C below.

2. Accidental Release

Chemical accidental release prevention requirements have been established in 40 CFR Part 68. Applicability is determined by comparing the amount of a listed substance on-site at a facility to its threshold quantity. Bowie has proposed using ammonia in association with the SCR NO_x control system. At the time of application the design specifications for the SCR system was not complete, thus, the type, concentration, and quantity to be stored on-site was not known. If more than a threshold quantity (20,000 pounds for aqueous or 10,000 pounds for anhydrous) will be stored on-site this will trigger the risk management planning requirements. A Risk Management Plan is required by the date on which a regulated substance is first present above the threshold quantity. Consequently, a Risk Management Plan for the storage and use of ammonia will be required before ammonia in excess of the threshold can be stored on-site.

In addition to a Risk Management Plan, under Section 112(r)(1) of the Clean Air Act Bowie also has a general duty to identify, prevent, and minimize the consequences of an accidental release of toxic chemicals.

3. Acid Rain

The combined cycle units are considered Phase II affected units under the Title IV Acid Rain Program and an Acid Rain permit must be obtained prior to operation. As part of its permit application, Bowie submitted an Acid Rain permit application. The proposed permit serves as a combined PSD, Title IV, and Title V permit. The permitted emission limits, monitoring, record keeping, and reporting requirements of the proposed permit incorporate the applicable Acid Rain provisions of 40 CFR Parts 72, 73, and 75.

As a new plant, Bowie does not hold SO_2 allowances and will have to obtain such allowances to sufficiently cover its previous year's emissions as of the allowance transfer deadline. Emission limits for NO_x are not applicable to the project because the Acid Rain provisions only apply to coal-fired units. Monitoring requirements from 40 CFR Part 75 are discussed in Section VI.

C. Regulatory Streamlining

The proposed Bowie project is subject to requirements under NSPS that are less stringent than those required in the proposed permit as a result of BACT. The permit has been drafted to reflect the more stringent requirements. The following analysis demonstrates the permit streamlining. Table 6 summarizes the requirements and demonstrates that the streamlined permit conditions are more stringent.

From NSPS Subpart GG, the emission limit for NO_x from the combustion turbines is established in §60.332(a)(1) as 0.01% by volume at 15% O_2, which corresponds to 75 ppmvd @15% O_2 (without correction for thermal efficiency). NO_x emissions from the turbines will be controlled by dry low-NO_x combustors and further controlled by an SCR system. The BACT analysis results in an emission rate for NO_x of 2.0 ppmvd @ 15% O_2, on a 3-hour average which is more stringent than the NSPS Subpart GG requirement. This emission limit will be restricted further to 2.0 ppmvd @ 15% O_2, on a 1-hour average after the first 18 months of operation unless Bowie makes the NO_x demonstration required by the permit. NSPS Subpart Da establishes an emission limit for NO_x of 0.20 lb/MMBtu for the duct burners. The total NO_x emission rate for each combined cycle system equates to 0.009 lb/MMBtu, which is also more stringent than the NSPS requirement.

The emission limit for SO_2 in NSPS Subpart GG is either a fuel sulfur content of 0.8% by weight or 150 ppmvd. Pipeline quality natural gas is the only fuel to be combusted in the turbines and it is inherently low in sulfur with a maximum allowable sulfur content in the natural gas of 0.75 grains/100 dry standard cubic foot (dscf). This equates to a weight percent of sulfur of 0.0024%, which is much lower than the NSPS limit of 0.8% by weight. NSPS Subpart Da establishes an SO_2 emission limit of 0.2 lb/MMBtu for the duct burners. The total SO_2 emission rate for each combined cycle system equates to 0.004 lb/MMBtu, which is more stringent than the NSPS.

Table 6. Permit Streamlining Analysis

Citation	Requirements	Proposed Permit Condition	Comparable Level of Stringency
Emission Limits	Turbine: NO_x: 40 CFR 60.332(a)(1), turbine < 75 ppmvd SO_2: 40 CFR 60.333(a), fuel content <0.8% by weight Duct burners: NO_x: 40 CFR 60.44a (d)(1), $\leq$ 1.6 lb/MW-hr SO_2: 40 CFR 60.43a(b)(2), $\leq$ 0.2 lb/MMBtu PM: 40 CFR 60 42a(a)(1) and (b), $\leq$ 0.03 lb/MMBtu, opacity $\leq$20% (6-min avg.)	Combined cycle units: BACT: 2.0 ppmvd @ 15% O_2, 3 hour average* Maximum allowable sulfur content of natural gas 0.75 grains/100 dscf, equates to 0.004 lb/MMBtu PM emission rate equates to 0.01 lb/MMBtu, opacity $\leq$10% (6-min avg)	Permit more stringent
Monitoring	40 CFR Part 75: CEMS for NO_x and O_2 (or carbon dioxide (CO_2)), and CMS for fuel flow 40 CFR 60.334(b), sulfur and nitrogen content of the fuel, daily or custom schedule	CEMS for NO_x and O_2 (or CO_2), and CMS for fuel flow Federal Energy Regulatory Commission-approved agreement for sulfur content	Permit as stringent
Testing	40 CFR 60.8, 60.335(b) and 40 CFR 60.48a, initial source testing and as required by Administrator	Initial performance testing and compliance via CEMS	Permit as stringent
Recordkeeping	40 CFR 60.49a(b), daily records for reporting	Fuel flow monitor and fuel usage records, records of emission rates and CEMS data	Permit as stringent
Reporting	40 CFR 60.7, 60.334(c), 60.49a(h), excess emissions 40 CFR 60.49a(a), performance test data 40 CFR 60.49a(b), reports for SO_2 and NO_x 40 CFR 60.49a(g), signed statement 40 CFR 60.49a(i), semi-annual reports	Semi-annual reports, excess emissions, performance test data, notifications	Permit as stringent

*Note: This emission limit may be reduced to 2.0 ppmvd on a 1-hour rolling average after the first 18 months of operation based on the NO_x demonstration required by the permit.

V. BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

The PSD regulations under Title I of the Federal Clean Air Act and A.A.C. R18-2-406.A, and the BACT requirements under those regulations, are applicable to the Bowie project for NO_x, CO, VOC, PM_{10}, and SO_2. The term "best available control technology" is defined in the ADEQ regulations as follows:

> "an emission limitation, including a visible emissions standard, based on the maximum degree of reduction for each air pollutant listed in R18-2-101(97)(a) which would be emitted from any proposed major source or major modification, taking into account energy, environmental, and economic impact and other costs, determined by the Director in accordance with R18-2-406(A)(4) to be achievable for such source or modification."

"A top-down" approach is recommended for determining BACT, and the analyses are to be performed on a source-by-source and pollutant-by-pollutant basis. This approach essentially ranks potential control technologies for each pollutant in order of effectiveness and ensures that the best technically and economically feasible option is chosen. As described in the Environmental Protection Agency's (EPA) New Source Review Workshop Manual, draft (final document never published), October 1990, the general methodology of this approach is as follows:

1. Identify potential control technologies, including combinations of control technologies, for each pollutant subject to PSD review.

2. Evaluate each control technology for technical feasibility; eliminate those determined to be technically infeasible.

3. Rank the remaining technically feasible control technologies in order of control effectiveness.

4. Assume the highest ranking technically feasible control represents BACT, unless it can be shown to result in adverse environmental, energy, or economic impacts.

5. Select BACT.

The NSR Workshop Manual also notes that, to complete the BACT process, an enforceable emission limit representing BACT must be included in the PSD permit. This emission limit must be met on a continual basis at all levels of operation, must demonstrate protection of short term ambient standards, and must be enforceable as a practical matter. In order for the emission limit to be enforceable as a practical matter, the permit must specify a reasonable compliance averaging time, consistent with established reference methods, and must include compliance verification procedures (i.e., monitoring requirements) designed to show compliance or non-compliance on a time period consistent with the applicable emission limit.

As required by PSD regulations, Bowie will be using air pollution control techniques for each pollutant subject to review that have been analyzed and are deemed to be "best available control technology," to control emissions from its emitting sources. The applicant provided a BACT analysis in its initial application. The analyses have been reviewed by ADEQ and the results are summarized below for each of the emitting units.

A. Combined Cycle Systems

The CTG/HRSG units will be equipped with an SCR system and low-NO_x combustors to control NO_x emissions to 2.0 parts per million by volume dry (ppmvd) @ 15% oxygen (O_2), 1-hour average. An oxidation catalyst will control CO and VOC emissions. Combustion controls and use of natural gas will mitigate emissions of PM_{10}. Emissions of SO_x (SO_2 and sulfur trioxide (SO_3)) will be limited by the maximum allowable sulfur content in the natural gas of 0.75 grains/100 dry standard cubic foot (dscf) and 8.7 pounds of SO_2/hr.

1. Particulate Matter Less than 10 Microns (PM_{10})

PM_{10} is a Clean Air Act regulated pollutant defined as particulate matter equal to or less than a nominal aerodynamic particle diameter of 10 microns. Particulate matter is typically described as in-stack or "filterable" and condensable PM. The amount of both filterable and condensable PM_{10} emissions from natural gas-fired combustion turbines should be very small relative to the total exhaust flow. Vendor data on expected PM_{10} emission rates are designed to allow for the high level of test error inherent in sampling for an extremely small quantity of PM_{10} in a very large exhaust flow. In order to reduce the amount of variability/error, longer sampling times than are normally used by stack testers during compliance testing can be used.

There are no known applications of add-on controls for the purpose of controlling PM_{10} from natural gas-fired units, because this fuel has little if no ash that would contribute to the formation of PM or PM_{10}. Table 7 lists PM_{10} emission rates and controls contained in EPA's RACT/BACT/LAER Clearinghouse (RBLC) for other recently permitted similar sources. The applicant has demonstrated that the use of good combustion practices and natural gas represents BACT for PM_{10}.

2. Nitrogen Oxides (NO_x)

The formation of NO_x from the combustion of fossil fuels can be attributed to two basic mechanisms – fuel NO_x and thermal NO_x. Fuel NO_x results from the oxidation of organically bound nitrogen in the fuel during the combustion process, and generally increases with increasing nitrogen content of the fuel. Because natural gas contains only small amounts of nitrogen, little fuel NO_x is formed during combustion.

The vast majority of the NO_x produced during the combustion of natural gas is from thermal NO_x, which results from a high-temperature reaction between nitrogen and oxygen in the combustion air. The generation of thermal NO_x is a function of combustion chamber design and the turbine operating parameters, including flame temperature, residence time (i.e., the amount of time the hot gas mixture is exposed to a given flame temperature), combustion pressure, and fuel/air ratios at the primary combustion zone. The rate of thermal NO_x formation is an exponential function of the flame temperature.

The reduction of NO_x emissions can be achieved by combustion controls and post-combustion flue gas treatment (i.e., NO_x is removed from the exhaust stream after it is generated). The applicant considered a number of measures for the control of NO_x emissions from the proposed project, including both in-combustor controls, such as water (or steam) injection and the use of dry low-NO_x combustors, and post-combustion techniques. SCR, Selective Non-Catalytic Reduction (SNCR), $SCONO_x$, and XONON were considered as post-combustion NO_x control systems. A comparison of the control systems proposed by the applicant and previously permitted control systems taken from the RBLC are presented in Table 8.

For large gas turbines such as those proposed, water and steam injection have been largely superseded by dry low-NO_x (DLN) combustors, due to the superior emission control performance and increased efficiency. DLN combustors are also effective in achieving lower NO_x emission levels without the need for large volumes of purified water. Both dry low-NO_x burners and water injection result in higher VOC and CO emissions than uncontrolled turbines, but these effects will be minimized by high combustion temperatures, adequate excess air, and good air-to-fuel mixing during combustion.

Table 7. CTG/HRSG BACT Comparison for PM_{10}

RBLC ID	Permit Date	Facility	Process	Control Technology	Emission Limit	Emission Limit Unit	Basis
AR-0043	2/27/01	Pine Bluff Energy LLC	CTG/HRSG	Good Combustion Practices	0.0065	lb/mmBtu	BACT
AL-0141	4/10/00	GPC-Goat Rock Combined Cycle	CTG/HRSG	Efficient Combustion	0.009	lb/mmBtu	BACT
AL-0162	1/8/01	Autauga Ville Combined Cycle Plant	CTG/HRSG	Good Combustion	0.009	lb/mmBtu	BACT
RI-0019	5/3/00	Reliant Energy Hope Gen. Facility	CTG/HRSG	Use of Natural Gas	0.009	lb/mmBtu	BACT
AZ	3/4/03	Bowie Power Station	CTG/HRSG	Good Combustion	0.01	lb/MMBtu	BACT
AL-0167	1/26/2001	Calhoun Power Company I, LLC	CTG	Good Combustion Practices	0.01	lb/mmBtu	BACT
MO-0053	1/1/96	Hawthorne Generating Station	CTG	Use of Natural Gas	0.01	lb/mmBtu	BACT
MO-0056	3/30/99	Associated Electric Cooperative, Inc.	CTG	Good Combustion Practices	0.01	lb/mmBtu	BACT
OK-0041	1/19/00	McClain Energy Facility	CTG/HRSG	Clean Fuels	0.01	lb/mmBtu	BACT
MS-0040	12/31/98	Mississippi Power Plant	CTG	Use of Natural Gas	0.011	lb/mmBtu	BACT
AL-0143	3/3/2000	AEC-McWilliams Plant	CTG/HRSG	Good Combustion Practices	0.012	lb/mmBtu	BACT
IN-0087	6/6/01	Duke Energy, Vigo LLC	CTG/HRSG	Good Combustion Practices	0.012	lb/mmBtu	BACT
AL-0169	2/5/2001	Blount Megawatt Facility	CTG	Good Combustion Practices	0.013	lb/mmBtu	BACT
AR-0035	8/24/00	Panda - Union Generating Station	CTG	Clean Fuels, Proper Operation	0.014	lb/mmBtu	BACT
AZ-0038	4/30/02	Gila Bend Power Generation Station	CTG/HRSG	Use of Natural Gas	0.014	lb/mmBtu	BACT
PA-0188	3/28/02	Fairless Energy LLC	CTG	Use of Natural Gas	0.014	lb/mmBtu	BACT
OK-0043	10/22/01	Weber’s Falls Energy Facility	CTG	Efficient Combustion	0.015	lb/mmBtu	BACT
MO-0058	5/9/00	Audrain Generating Station	CTG	Good Combustion Practices	0.016	lb/mmBtu	BACT
OK-0070	6/13/02	Genova OK I Power Project	CTG/HRSG	Low Sulfur Fuel, Efficient Combustion	0.019	lb/mmBtu	BACT
AL-0132	11/29/99	Tenaska Alabama Generating Station	CTG/HRSG	Efficient Combustion	0.02	lb/mmBtu	BACT
DE-0016	10/17/00	Hay Road Power Complex Units 5-8	CTG	Clean Fuels	0.02	lb/mmBtu	BACT
WA-0289	2/22/02	TransAlta Centralia - Big Hanaford	CTG/HRSG	Good Combustion, Natural Gas	4.1	lb/hour	BACT
CA	9/1/01	Metcalf Energy Center	CTG/HRSG	Use of Natural Gas	9.0	lb/hour	BACT
CA	3/1/01	Western Midway Sunset Power	CTG/HRSG	Use of Natural Gas	9.4	lb/hour	BACT-CA
OK	1/21/00	Oneta Generating Station	CTG/HRSG	Use of Natural Gas	9.4	lb/hour	BACT
CA	3/1/01	Western Midway Sunset Power	CTG/HRSG	Use of Natural Gas	10.7	lb/hour	BACT-CA
MI-0267	6/7/01	Renaissance Power LLC	CTG/HRSG	Good Combustion Practices	11.0	lb/hour	BACT
CA	3/1/01	Mountainview Power Project	CTG/HRSG	Use of Natural Gas	11.5	lb/hour	BACT-CA
CA	10/1/00	Blythe Energy	CTG/HRSG	Use of Natural Gas	12.0	lb/hour	BACT-CA
CA	2/1/02	Delta Energy Center	CTG/HRSG	Use of Natural Gas	14.7	lb/hour	BACT-CA

RBLC ID	Permit Date	Facility	Process	Control Technology	Emission Limit	Emission Limit Unit	Basis
IN-0086	5/9/01	Mirant Sugar Creek LLC	CTG/HRSG	Good Combustion Practices	18	lb/hour	BACT
TX-0234	1/8/02	Edinburg Energy Limited Partnership	CTG	Use of Natural Gas	18	lb/hour	BACT
WV-0014	12/18/01	Panda Culloden Generating Station	CTG/HRSG	Use of Natural Gas	18	lb/hour	BACT
OK-0036	12/10/01	Stephens Energy Facility	CTG/HRSG	Use of Natural Gas	19.1	lb/hour	BACT
CA	4/1/01	Otay Mesa Generating Project	CTG/HRSG	Use of Natural Gas	20.0	lb/hour	
FL-0225	8/17/01	El Paso Broward Energy Center	CTG/HRSG	Use of Natural Gas	20.0	lb/hour	BACT
FL-0227	9/7/01	El Paso Belle Glade Energy Center	CTG/HRSG	Use of Natural Gas	20.0	lb/hour	BACT
IN-0085	6/7/01	PSEG Lawrenceburg Energy Facility	CTG/HRSG	Good Combustion	21	lb/hour	BACT
FL-0226	9/11/01	El Paso Manatee Energy Center	CTG/HRSG	Use of Natural Gas	21.8	lb/hour	BACT
MA-0024	4/16/99	ANP Blackstone	CTG/HRSG	Use of Natural Gas	21.8	lb/hour	BACT
MA-0025	8/4/99	ANP Bellingham	CTG/HRSG	Use of Natural Gas	22.6	lb/hour	BACT
MO	8/19/99	Kansas City Power & Light Hawthorn	CTG/HRSG	Combustion Controls	24.0	lb/hour	BACT
TX-0350	1/31/02	Ennis Tractebel Power	CTG/HRSG	Use of Natural Gas	25.62	lb/hour	BACT
AZ-0034	2/15/01	Harquahala Generating Project	CTG/HRSG	Combustion Controls	27.8	lb/hour	BACT
AR	12/29/00	Duke Energy Hot Springs	CTG/HRSG	Combustion Controls	29.4	lb/hour	BACT
MN	11/17/00	XCEL Energy, Black Dog	CTG/HRSG	Use of Natural Gas	29.4	lb/hour	BACT
AZ	9/30/04 Dft	Dome Valley Energy Partners, LLC	CTG/HRSG	Good Combustion, Natural Gas	29.8	lb/hour	BACT
AZ	2003 Dft	La Paz Generating Facility (W501F)	CTG/HRSG	Use of Natural Gas	30.3	lb/hour	BACT
MI-0256	1/12/01	Covert Generating Co LLC	CTG/HRSG	Good Combustion Practices	33.8	lb/hour	BACT
AZ	2003 Dft	La Paz Generating Facility (GE 7FA)	CTG/HRSG	Use of Natural Gas	45.5	lb/hour	BACT

Table 8. CTG/HRSG BACT Comparison for NO_x

RBLC ID	Permit Date	Facility	Process	Control Technology	Emission Limit	Emission Limit Unit	Basis
MA	9/11/00	IDC Bellingham	CTG/HRSG	SCR	1.5	ppm	LAER
AZ	9/30/04 Dft	Dome Valley Energy Partners, LLC	CTG/HRSG	SCR, Dry Low NOx Burner	2.0	ppmv	BACT
AZ-0039	3/7/03	Salt River Project/Santan Gen. Plant	CTG/HRSG	SCR	2.0	ppm	LAER
AZ-0043	11/12/03	Duke Energy Arlington Valley	CTG/HRSG	SCR	2.0	ppm	BACT
CA	4/1/01	Otay Mesa	CTG/HRSG	SCR	2.0	ppmv	BACT -CA
CA	5/21/01	Three Mountain Power	CTG/HRSG	SCR	2.0	ppm	BACT-CA
CA-0997	9/1/03	Sacramento Municipal Utility District	CTG	SCR	2.0	ppm	LAER
CT-0148	6/22/99	Lake Road Generating Company	CTG	SCR, Dry Low NOx Burner	2.0	ppmv	LAER
MA-0024	4/16/99	ANP Blackstone	CTG	SCR, Dry Low NOx Burner	2.0	ppmv	LAER
MA-0025	8/4/99	ANP Bellingham	CTG	SCR, Dry Low NOx Burner	2.0	ppmv	LAER
MA-0029	1/25/00	Sithe Mystic Development	CTG/HRSG	SCR, Dry Low NOx Burner	2.0	ppmv	LAER
OR-0043	5/11/04	Umatilla Generating - PG&E	CTG/HRSG	SCR, Dry Low NOx Burner	2.0	ppmvd	
PA-0226	4/9/02	Limerick Partners, LLC	CTG/HRSG	Low NOx Burners	2.0	ppm	LAER
RI-0019	5/3/00	Reliant Energy Hope Gen. Facility	CTG/HRSG	SCR, Dry Low NOx Burner	2.0	ppmv	BACT
WA-0299	4/17/03	Sumas Energy 2 - NESCO	CTG	SCR, Dry Low NOx Burner	2.0	ppmvd	BACT
AZ	3/4/03	Bowie Generating Station	CTG/HRSG	SCR, Dry Low NOx Burner	2.5/2.0	ppmv	BACT
AZ-0038	4/30/02	Gila Bend Power Generation Station	CTG/HRSG	SCR, Dry Low NOx Burner	2.5/2.0	ppmv	BACT
AL-0185	7/12/02	Barton Shoals Energy, LLC	CTG/HRSG	SCR, Dry Low NOx Burner	2.5	ppm	BACT
AZ-0033	3/22/01	Mesquite Generating Station	CTG/HRSG	SCR, Dry Low NOx Burner	2.5	ppmv	BACT
AZ-0034	2/15/01	Harquahala Generating Project	CTG/HRSG	SCR, Dry Low NOx Burner	2.5	ppmv	BACT
CA	12/2/99	Sutter Power Plant	CTG/HRSG	SCR, Dry Low NOx Burner	2.5	ppmv	BACT
CA	5/30/01	Contra Costa	CTG/HRSG	SCR, Dry Low NOx Burner	2.5	ppmv	BACT-CA
CA	12/18/01	Elk Hills Power Project	CTG/HRSG	SCR, Dry Low NOx Burner	2.5	ppmv	BACT-CA
CA	2/1/02	Delta Energy Center	CTG/HRSG	SCR	2.5	ppm	BACT-CA
CA	3/1/01	Mountain View Power Project	CTG/HRSG	SCR	2.5	ppm	BACT-CA
CA	10/1/00	Blythe Energy	CTG/HRSG	SCR	2.5	ppm	BACT-CA
CA	3/1/01	Western Midway Sunset Powe	CTG/HRSG	SCR	2.5	ppm	BACT-CA
CA	9/1/01	Metcalf Energy Center	CTG/HRSG	SCR	2.5	ppm	
FL-0225	8/17/01	El Paso Broward Energy Center	CTG/HRSG	SCR, Dry Low NOx Burner	2.5	ppmv	BACT
FL-0226	9/11/01	El Paso Manatee Energy Center	CTG/HRSG	SCR, Dry Low NOx Burner	2.5	ppmv	BACT

RBLC ID	Permit Date	Facility	Process	Control Technology	Emission Limit	Emission Limit Unit	Basis
FL-0227	9/7/01	El Paso Belle Glade Energy Center	CTG/HRSG	SCR, Dry Low NOx Burner	2.5	ppmv	BACT
FL-0241	1/17/02	CPV Cana Power Generation Facility	CTG/HRSG	SCR, DLN, Wet Injection	2.5	ppmvd	BACT
FL-0244	4/16/03	FPL Martin	CTG/HRSG	SCR, Dry Low NOx Burner	2.5	ppmvd	BACT
FL-0245	4/15/03	FPL Manatee - Unit 3	CTG/HRSG	SCR, Dry Low NOx Burner	2.5	ppmvd	BACT
FL-0256	9/8/03	FPC - Hines Energy Complex	CTG/HRSG	SCR, Dry Low NOx Burner	2.5	ppmvd	BACT
GA	3/24/03	GenPower Rincon	CTG/HRSG	SCR	2.5	ppm	
GA-0105	4/17/03	McIntosh Combined Cycle Facility	CTG/HRSG	SCR, Dry Low NOx Burner	2.5	ppm	BACT
ME	12/4/98	Westbrook Power LLC	CTG/HRSG	SCR	2.5	ppm	LAER
NC-0094	1/9/02	GenPower Earleys, LLC	CTG/HRSG	SCR, Dry Low NOx Burner	2.5	ppmvd	BACT
NC-0095	5/28/02	Mirant Gastonia	CTG/HRSG	SCR, Dry Low NOx Burner	2.5	ppmvd	BACT
NC-0101	1/23/04	Forsyth Energy Projects	CTG/HRSG	SCR, Dry Low NOx Burner	2.5	ppm	BACT
NH-0011	4/26/99	AES Londonderry, LLC	CTG	SCR, Dry Low NOx Burner	2.5	ppmv	BACT
NH-0012	4/26/99	Newington Energy LLC	CTG	SCR, Dry Low NOx Burner	2.5	ppmv	BACT
NJ-0043	3/28/02	Liberty Generating Station	CTG/HRSG	SCR	2.5	ppmvd	Other
OR-0035	1/16/02	Port Westward - Portland General	CTG	SCR, Dry Low NOx Burner	2.5	ppm	BACT
OR-0039	12/30/03	California Oregon Border - Peoples	CTG/HRSG	SCR, Dry Low NOx Burner	2.5	ppmvd	BACT
OR-0040	3/12/03	Klamath Generation LLC - Pacific Power	CTG/HRSG	SCR, Dry Low NOx Burner	2.5	ppmvd	BACT
PA-0160	10/10/00	Calpine Construction Finance Co.	CTG	SCR, Dry Low NOx Burner	2.5	ppmv	LAER
PA-0188	3/28/02	Fairless Energy LLC	CTG/HRSG	SCR, Dry Low NOx Burner	2.5	ppmv	LAER
PA-0189	1/16/02	Connectiv - Bethlehem North	CTG/HRSG	SCR, DLN, Wet Injection	2.5	ppmvd	LAER
PA-0223	1/30/02	Duke Energy Fayette, LLC	CTG/HRSG	SCR, Dry Low NOx Burner	2.5	ppmvd	LAER
SC-0064	5/28/02	Jasper County Generating Facility	CTG	SCR, Dry Low NOx Burner	2.5	ppm	
VA-0260	5/1/02	Henry County Power	CTG/HRSG	SCR, Dry Low NOx Burner	2.5	ppm	BACT
VA-0261	9/6/02	CPV Cunningham Creek	CTG/HRSG	SCR, Dry Low NOx Burner	2.5	ppm	BACT
VA-0287	12/1/03	James City Energy Park	CTG/HRSG	SCR, Dry Low NOx Burner	2.5	ppmvd	BACT
VA-0289	2/5/04	Duke Energy Wythe, LLC	CTG/HRSG	SCR, Dry Low NOx Burner	2.5	ppmvd	BACT
WA-0306	9/20/02	Cliffs Energy Project - GNA Energy	CTG	SCR, Dry Low NOx Burner	4.5	ppmvd	BACT
WA-0288	9/4/01	Longview Energy Development	CTG/HRSG	SCR	2.5	ppmv	BACT
WA-0291	1/3/03	Wallula Power - Newport Northwest	CTG/HRSG	SCR	2.5	ppmvd	BACT
WY-0061	4/4/03	Black Hills Corp - Neil Simpson Two	CTG/HRSG	SCR, Dry Low NOx Burner	2.5	ppm	BACT

RBLC ID	Permit Date	Facility	Process	Control Technology	Emission Limit	Emission Limit Unit	Basis
CO-0052	8/11/02	Rocky Mountain Energy Center	CTG/HRSG	SCR, Dry Low NOx Burner	3.0	ppm	BACT
DE-0016	10/17/00	Hay Road Power Complex Units 5-8	CTG	SCR, Dry Low NOx Burner	3.0	ppmv	LAER
GA	1/15/02	Oglethorpe Power Corp - Wansley	CTG/HRSG	SCR	3.0	ppm	
GA-0101	10/23/02	Murray Energy Facility	CTG/HRSG	SCR, Dry Low NOx Burner	3.0	ppm	BACT
GA-0102	1/15/02	Wansley Combined Cycle Energy	CTG/HRSG	SCR, Dry Low NOx Burner	3.0	ppm	BACT
IA	7/23/02	Entergy - Hawkeye Generation, LLC	CTG/HRSG	SCR, Dry Low NOx Burner	3.0	ppm	BACT
IA-0058	4/10/02	MidAmerican Energy, Des Moines Power	CTG/HRSG	SCR, Dry Low NOx Burner	3.0	ppm	BACT
IN-0085	6/7/01	PSEG Lawrenceburg Energy Facility	CTG/HRSG	SCR	3.0	ppmv	BACT
IN-0086	5/9/01	Mirant Sugar Creek LLC	CTG/HRSG	SCR	3.0	ppmv	BACT
IN-0114	7/24/02	Mirant Sugar Creek LLC	CTG/HRSG	SCR, Dry Low NOx Burner	3.0	ppmvd	BACT
MI-0357	2/4/03	Kalkaska Generating LLC	CTG/HRSG	SCR, Dry Low NOx Burner	3.0	ppmvd	BACT
MI-0361	1/30/03	South Shore Power LLC	CTG/HRSG	SCR, Dry Low NOx Burner	3.0	ppmvd	BACT
VA-0250	4/30/02	Tenaska Bear Garden	CTG	SCR	3.0	ppm	BACT
VA-0256	1/20/02	Tenaska Fluvanna	CTG/HRSG	SCR	3.0	ppm	BACT
WA-0289	2/22/02	TransAlta Centralia - Big Hanaford	CTG/HRSG	SCR, Dry Low NOx Burner	3.0	ppmvd	BACT
AR-0035	8/24/00	Panda - Union Generating Station	CTG	SCR, Dry Low NOx Burner	3.5	ppmv	BACT
AR-0040	12/29/00	Duke Energy Hot Springs	CTG/HRSG	SCR, Dry Low NOx Burner	3.5	ppmv	BACT
AR-0051	4/1/02	Duke Energy - Jackson Facility	CTG/HRSG	SCR, Dry Low NOx Burner	3.5	ppm	BACT
AR-0070	8/23/02	Genova Arkansas I, LLC	CTG/HRSG	SCR, Dry Low NOx Burner	3.5	ppmvd	BACT
FL-0214	2/5/01	CPV Gulfcoast Power Generating	CTG	SCR, Dry Low NOx Burner	3.5	ppmv	BACT
FL-0239	3/27/02	Jacksonville Electric Authority Brandy	CTG/HRSG	SCR, Dry Low NOx Burner	3.5	ppmvd	BACT
MI-0267	6/7/01	Renaissance Power LLC	CTG/HRSG	SCR, Dry Low NOx Burner	3.5	ppmv	BACT
MI-0365	1/28/03	Mirant Wyandotte LLC	CTG/HRSG	SCR, Dry Low NOx Burner	3.5	ppmv	BACT
MS-0055	6/24/02	El Paso Merchant Energy CO.	CTG/HRSG	SCR, Dry Low NOx Burner	3.5	ppmv	BACT
MS-0059	9/24/02	Pike Generation Facility	CTG	SCR, Dry Low NOx Burner	3.5	ppmv	BACT
NC-0086	1/10/02	Fayetteville Generation	CTG/HRSG	SCR, Dry Low NOx Burner	3.5	ppmvd	BACT
NE-0023	5/29/03	Nebraska Public Power- Beatrice Station	CTG	SCR, Dry Low NOx Burner	3.5	ppm	BACT
NV-0033	8/19/04	El Dorado Energy, LLC	CTG	SCR, Dry Low NOx Burner	3.5	ppm	BACT
OK-0036	12/10/01	Stephens Energy Facility	CTG/HRSG	SCR, Dry Low NOx Burner	3.5	ppmv	BACT
OK-0043	10/22/01	Webers Falls Energy Facility	CTG	SCR, Dry Low NOx Burner	3.5	ppmv	BACT

RBLC ID	Permit Date	Facility	Process	Control Technology	Emission Limit	Emission Limit Unit	Basis
OK-0070	6/13/02	Genova OK I Power Project	CTG/HRSG	SCR, Dry Low NOx Burner	3.5	ppmvd	BACT
OK-0090	3/21/03	Duke Energy Stephens, LLC	CTG/HRSG	SCR, Dry Low NOx Burner	3.5	ppm	BACT
OK-0096	6/6/03	Redbud Power Plant	CTG	SCR, Dry Low NOx Burner	3.5	ppmvd	BACT
TN-0144	2/1/02	Haywood Energy Center (Calpine)	CTG/HRSG	SCR, Dry Low NOx Burner	3.5	ppm	BACT
TX-0384	12/13/02	Steag (Brazos Valley)	CTG/HRSG	SCR	3.5	ppm	BACT
VA-0256	1/11/02	CPV Fluvanna	CTG/HRSG	SCR	3.5	ppm	BACT
VA-0255	11/18/02	VA Power - Possum Point	CTG/HRSG	Water Injection, SCR	3.5	ppmvd	LAER
WI-0174	9/20/00	Badger Generating Co LLC	CTG/HRSG	SCR, Dry Low NOx Burner	3.5	ppmv	BACT
WV-0014	12/18/01	Panda Culloden Generating Station	CTG	SCR, Dry Low NOx Burner	3.5	ppmv	BACT
LA-0157	3/8/02	Perryville Power Station	CTG	SCR, Dry Low NOx Burner	4.5	ppm	BACT
MI-0363	1/7/03	Bluewater Energy Center LLC	CTG	SCR, Dry Low NOx Burner	4.5	ppmv	BACT
TX-0407	12/6/02	Steag-Stearne	CTG/HRSG	SCR, Dry Low NOx Burner	5.0	ppm	
OK-0056	2/12/02	Horseshoe Energy Project	CTG	SCR	12.5	ppm	BACT
TX-0234	1/8/02	Edinburg Energy Limited Partnership	CTG	Emission Limits	15.0	ppm	BACT

1. Table Limited to NO_x Emission Limit less than or equal to 15 ppmv

Among post-combustion control systems, the XONON catalytic system was rejected because it is not technically feasible. XONON is an emerging technology and is not commercially available at this time for CTGs of the size proposed for this project. SNCR was also rejected as a possible control system because the technology requires gas temperatures in the range of 1200 to 2000 ºF, and the exhaust temperature for the proposed turbines, i.e. 600 ºF, is below the minimum SNCR operating temperature.

The SCR process is a post-combustion control technology in which injected ammonia (NH_3) reacts with NO_x in the presence of a catalyst to form water and nitrogen. The catalyst's active surface is usually a noble metal, base metal (titanium or vanadium) oxide, or a zeolite-based material. The geometric configuration of the catalyst body is designed for maximum surface area and minimum back-pressure on the turbine. An ammonia injection grid is located upstream of the catalyst body and is designed to disperse ammonia uniformly throughout the exhaust flow before it enters the catalyst unit. The desired level of NO_x emission reduction is a function of the catalyst volume and ammonia-to-NO_x (NH_3/NO_x) ratio. For a given catalyst volume, higher NH_3/NO_x ratios can be used to achieve higher NO_x emission reductions, but can result in undesired increased levels of unreacted NH_3 (called ammonia slip).

SCR has been demonstrated to be effective at numerous installations throughout the United States. Typically SCR is used in conjunction with other wet or dry NO_x combustion controls (e.g., DLN). Because SCR is a post-combustion control, emissions from both turbines and duct burners can be controlled.

SCONO$_x$ is another type of post-combustion control. The SCONO$_x$ system uses a proprietary potassium carbonate coated oxidation catalyst to remove both NO_x and CO. The SCONO$_x$ system does not use a reagent such as ammonia but instead utilizes natural gas as the basis for a proprietary catalyst regeneration process. The nitrogen oxide (NO) present in the flue gas is reduced in a two-step process. First, NO is oxidized to NO_2 and adsorbed onto the catalyst. For the second step, a regenerative gas is passed across the catalyst periodically. This gas desorbs the NO_2 from the catalyst in a reducing atmosphere of hydrogen (H_2) which results in the formation of nitrogen (N_2) and water (H_2O) as the desorption products. For the regeneration/desorption step to occur there must be no oxygen (O_2) present during this step. The CO present in the flue gas is oxidized to carbon dioxide (CO_2) as part of the SCONO$_x$ process.

From the analysis, the highest ranking technically feasible control for NO_x is considered to be the use of either SCR or $SCONO_x$ in conjunction with dry low-NO_x combustors. An analysis of the cost-effectiveness for $SCONO_x$ and SCR at 2.0 and 2.5 ppmvd at 15% O_2 was used to determine the highest ranking, economically feasible control. Note that $SCONO_x$ also controls CO and does not require ammonia, and these factors were taken into account in the cost-effectiveness analysis. The cost-effectiveness of $SCONO_x$ ($37,346/ton) when compared to SCR results in $SCONO_x$ being considered not economically feasible. The total dollar per ton and incremental cost-effectiveness of SCR at NO_x levels of 2.5 and 2.0 ppmvd at 15% O_2 were also investigated. Cost data for the two levels of control for SCR was provided by the applicant in the permit application update dated December 2004. "...the catalyst cost differential between a 2.5 ppm and a 2 ppm SCR system has decreased dramatically over the last several months." The cost analyses were not revised and 2 ppm NO_x was determined to be economically feasible.

After considering the available data, and the emission limits for other recently permitted similar projects, ADEQ concludes that DLN combustors in combination with an SCR control system that reduces NO_x to 2.0 ppmvd at 15% O_2 represents BACT for the CTG/HRSG. The proposed combined cycle systems include both duct firing and power augmentation. Combined cycle systems currently in operation, which form the basis of what has been achieved by similar systems, do not include both duct firing and power augmentation.

The emission limit is initially proposed at 2.0 ppmvd (3-hr average) with a demonstration period that will reduce the emission limit to 2.0 ppmvd (1-hr average) after the first 18 months of operation unless Bowie makes the NO_x demonstration required by the permit. ADEQ is including the 18 month demonstration period given that 1) the 2.0 ppmvd NO_x BACT limit has only recently been demonstrated, 2) it is consistent with other recently permitted combined cycle system sources in EPA Region IX, and 3) that the proposed source includes both duct firing and power augmentation. As per vendor data, power augmentation, in addition to duct firing, increases NO_x emissions for the proposed combined cycle systems.

The permit states that the emission limit will be reduced to 2.0 ppmvd on a 1-hour average at 15% O_2, excluding periods of start-up and shutdown, after the first 18 months of operation. If the facility has not been able to reasonably and consistently meet a NO_x limit of 2.0 ppmvd on a 1-hour average, the facility is required to submit a written request to the Director prior to the 18 month anniversary, requesting a different limit not to exceed 2.0 ppmvd on a 3-hour average. The Department will review the request and determine the final emission limit for the remaining permit term.

As noted above, operation of SCR systems can result in undesired emissions of unreacted NH_3, or ammonia slip. Other similar sources permitted in EPA Region IX have been limited to 10 ppmvd NH_3. Consequently, ADEQ is establishing a conditional ammonia slip emission limit of 10 ppmvd at 15% O_2 (24-hour average) for the first 18 months, with a similar demonstration period as NO_x, that may reduce the ammonia emission limit to 7.5 ppmvd (24-hr average)

3. Carbon Monoxide (CO)

CO is a product of incomplete combustion. CO formation is limited by ensuring complete and efficient combustion of the fuel in the combustion turbine. High combustion temperatures, adequate excess air, and good air/fuel mixing during combustion minimize CO emissions. Measures taken to minimize the formation of NO_x during combustion may inhibit complete combustion, which could increase CO emissions. Lowering combustion temperatures through premixed fuel combustion can be counterproductive with regard to CO emissions. However, improved air/fuel mixing inherent in newer combustor designs and control systems limits the impact of fuel staging on CO emissions.

The applicant considered catalytic oxidation and good combustion controls as possible control technologies. As noted previously, $SCONO_x$ can control both NO_x and CO, and the additional control of CO was incorporated into the cost analysis. $SCONO_x$ was rejected for economic considerations and is not considered further. An oxidation catalyst represents the most stringent control option, thus, no further analysis of control technologies is required.

In the original application and subsequent submittals, the applicant presented cost-effectiveness analyses for three levels of control, 4, 3, and 2 ppmvd. It was determined that 2 ppmvd was not economically feasible, and that 3 ppmvd is cost-effective and is proposed as BACT.

A comparison of the control systems considered by the applicant are presented and compared with previously permitted CO control systems taken from the RBLC in Table 9. A review of the RBLC data in Table 9 indicates that combined cycle projects have recently been permitted both with and without an oxidation catalyst.

The applicant is proposing the use of an oxidation catalyst, in addition to combustion controls, to reduce CO to 3 ppmvd at 15% O_2 with and without duct firing and power augmentation, on a 3-hour average. Upon review of the data, ADEQ concurs with and approves the applicant's BACT proposal.

Table 9. CTG/HRSG BACT Comparison for CO

RBLC ID	Permit Date	Facility	Process	Control Technology	Emission Limit	Emission Limit Unit	Basis
CT-0148	6/22/1999	Lake Road Generating Company	CTG	Oxidation Catalyst	2	ppmv	BACT
GA-0098	3/24/2003	GenPower Rincon	CTG	Oxidation Catalyst	2	ppm	BACT
GA	4/17/2003	Savannah Electric and Power - McIntosh		Oxidation Catalyst	2	ppm	
GA	1/15/2002	Oglethorpe Power Corp - Wansley		Oxidation Catalyst	2	ppm	
GA-0102	1/15/2002	Wansley Combined Cycle Energy Facility	CTG/HRSG	Good Combustion Practices	2	ppm	BACT
GA-0105	4/17/2003	McIntosh Combined Cycle Facility	CTG/HRSG	Oxidation Catalyst	2	ppm	BACT
MA	9/11/2000	IDC Bellingham	CTG/HRSG	Oxidation Catalyst	2	ppm	
MA-0029	1/25/2000	Sithe Mystic Development	CTG/HRSG	Oxidation Catalyst	2	ppm	BACT
NJ-0043	3/28/2002	Liberty Generating Station	CTG/HRSG	Oxidation Catalyst	2	ppmvd	Other
OR-0039	12/30/2003	California Oregon Border - Peoples Energy	CTG/HRSG	Oxidation Catalyst	2	ppmvd	BACT
WA	4/20/2003	Plymouth Generating Facility		Oxidation Catalyst	2	ppmvd	
WA	6/19/2003	Frederickson Power II - West Coast Energy		Oxidation Catalyst	2	ppmvd	
WA-0288	9/4/2001	Longview Energy Development	CTG/HRSG	Oxidation Catalyst	2	ppmvd	BACT
WA-0291	1/3/2003	Wallula Power - Newport Northwest Gen	CTG/HRSG	Oxidation Catalyst	2	ppmvd	BACT
WA-0299	4/17/2003	Sumas Energy 2 - NESCO	CTG/HRSG	Oxidation Catalyst	2	ppmvd	BACT
WI-0114	1/13/1995	LS Power	CTG/HRSG	Oxidation Catalyst	2	ppmv	BACT
OH-0248	9/24/2002	Lawrence Energy - Calpine Corporation		Oxidation Catalyst	2	ppm	BACT
PA-0189	1/16/2002	Connectiv - Bethlehem North	CTG/HRSG	Good Combustion Practices	2.5	ppm	BACT
NV-0033	8/19/2004	El Dorado Energy, LLC	CTG	Oxidation Catalyst	2.6	ppm	LAER
AZ	3/4/03	Bowie Generating Station	CTG/HRSG	Oxidation Catalyst	3	ppmv	BACT
AZ-0039	3/7/2003	Salt River Project/Santan Gen. Plant	CTG/HRSG	Oxidation Catalyst	3	ppm	LAER
AZ-0043	11/12/2003	Duke Energy Arlington Valley	CTG/HRSG	Oxidation Catalyst	3	ppm	BACT
MI	2/8/1999	Wyandotte Energy	CTG/HRSG	Oxidation Catalyst	3	ppm	LAER
MI-0267	6/7/2001	Renaissance Power LLC	CTG/HRSG	Oxidation Catalyst	3	ppmv	BACT
PA-0188	3/28/2002	Fairless Energy LLC	CTG/HRSG	Oxidation Catalyst	3	ppmvd	BACT
UT	5/17/2004	Pacificorp - Currant Creek Power Project		Oxidation Catalyst	3	ppm	
VA-0261	9/6/2002	CPV Cunningham Creek	CTG/HRSG	Oxidation Catalyst	3.1	ppm	BACT
MI-0365	1/28/2003	Mirant Wyandotte LLC	CTG/HRSG	Oxidation Catalyst	3.8	ppm	BACT
AZ-0033	3/22/2001	Mesquite Generating Station	CTG/HRSG	Oxidation Catalyst	4	ppmv	BACT
AZ-0038	4/30/2002	Gila Bend Power Generation Station	CTG/HRSG	Oxidation Catalyst	4	ppm	BACT

RBLC ID	Permit Date	Facility	Process	Control Technology	Emission Limit	Emission Limit Unit	Basis
CA	12/2/1999	Sutter Power Plant	CTG/HRSG	Oxidation Catalyst	4	ppmv	BACT-CA
CA	12/18/2001	Elk Hills Power Project	CTG/HRSG	Oxidation Catalyst	4	ppmv	BACT-CA
CA	5/21/2001	Three Mountain Power	CTG/HRSG		4	ppm	BACT-CA
CA-0997	9/1/2003	Sacramento Municipal Utility District		Good Combustion Control	4	ppm	LAER
MI-0361	1/30/2003	South Shore Power LLC		Oxidation Catalyst	4	ppmvd	BACT
OR	7/3/2002	Summit Westward - Westward Energy LLC		Good Combustion Practices	4	ppmvd	
WA	9/20/2002	Cliffs Energy Project - GNA Energy		Oxidation Catalyst	4	ppmvd	
WI-0174	9/20/2000	Badger Generating Co LLC	CTG/HRSG	Oxidation Catalyst	4	ppmv	BACT
OR-0035	1/16/2002	Port Westward - Portland General Electric		Oxidation Catalyst	4.9	ppmvd	BACT
CA	10/1/2000	Blythe Energy	CTG/HRSG		5	ppm	BACT-CA
IA	7/23/2002	Hawkeye Generation, LLC		Oxidation Catalyst	5	ppm	
IA	12/20/2002	Interstate Power and Light - Exira Station		Oxidation Catalyst	5	ppm	
IA-0058	4/10/2002	MidAmerican Energy, Des Moines Power		Oxidation Catalyst	5	ppm	BACT
MI-0256	1/12/2001	Covert Generating Co LLC	CTG/HRSG	Oxidation Catalyst	5	ppmv	BACT
MI-0357	2/4/2003	Kalkaska Generating LLC	CTG/HRSG	Oxidation Catalyst	5	ppmvd	BACT
OR-0040	3/12/2003	Klamath Generation LLC - Pacific Power	CTG/HRSG	Oxidation Catalyst	5	ppmvd	BACT
PA-0223	1/30/2002	Duke Energy Fayette, LLC	CTG/HRSG	Oxidation Catalyst	5	ppm	BACT
CA	4/1/2001	Otay Mesa	CTG/HRSG	Oxidation Catalyst	6	ppmv	BACT-CA
CA	5/30/2001	Contra Costa	CTG/HRSG	Oxidation Catalyst	6	ppmv	BACT-CA
CA	3/1/2001	Mountainview Power Project	CTG/HRSG	Oxidation Catalyst	6	ppm	BACT-CA
CA	3/1/2001	Western Midway Sunset Power Project	CTG/HRSG	Oxidation Catalyst	6	ppm	BACT-CA
CA	9/1/2001	Metcalf Energy Center	CTG/HRSG		6	ppm	
IN-0085	6/7/2001	PSEG Lawrenceburg Energy Facility	CTG/HRSG	Good Combustion	6	ppmv	BACT
FL-0225	8/17/2001	El Paso Broward Energy Center	CTG/HRSG	Combustion Controls	7.4	ppmv	BACT
FL-0226	9/11/2001	El Paso Manatee Energy Center	CTG/HRSG	Combustion Controls	7.4	ppmv	BACT
FL-0227	9/7/2001	El Paso Belle Glade Energy Center	CTG/HRSG	Combustion Controls	7.4	ppmv	BACT
OK	1/21/2000	Oneta Generating Station	CTG/HRSG	Combustion Controls	7.8	ppm	BACT
FL-0241	1/17/2002	CPV Cana Power Generation Facility		Good Combustion Practices	8	ppmvd	BACT
AR-0070	8/23/2002	Genova Arkansas I, LLC		Good Combustion Practices	8.2	ppmvd	BACT
OK-0070	6/13/2002	Genova OK I Power Project	CTG/HRSG	Combustion Controls	8.2	ppm	BACT
WV-0014	12/18/2001	Panda Culloden Generating Station	CTG	Good Combustion	8.2	ppmv	BACT

RBLC ID	Permit Date	Facility	Process	Control Technology	Emission Limit	Emission Limit Unit	Basis
CO	6/19/2000	Fort St. Vrain	CTG/HRSG	Combustion Controls	9	ppm	BACT
CO-0052	8/11/2002	Rocky Mountain Energy Center		Oxidation Catalyst	9	ppmvd	BACT
DE-0016	10/17/2000	Hay Road Power Complex Units 5-8	CTG	Good Combustion	9	ppmv	BACT
FL	1/9/2002	TECO Bayside Power Station (repowering)		Good Combustion Practices	9	ppm	
FL-0214	2/5/2001	CPV Gulfcoast Power Generating STN	CTG	Combustion Controls	9	ppmv	BACT
FL-0223	11/4/1999	Lake Worth Generating, LLC	CTG	Combustion Design	9	ppmv	BACT
IN-0086	5/9/2001	Mirant Sugar Creek LLC	CTG/HRSG	Good Combustion	9	ppmv	BACT
IN-0087	6/6/2001	Duke Energy, Vigo LLC	CTG/HRSG	Good Combustion	9	ppmv	BACT
IN-0114	7/24/2002	Mirant Sugar Creek LLC		Good Combustion Practices	9	ppmvd	BACT
NC-0086	1/10/2002	Fayetteville Generation		Good Combustion Practices	9	ppm	BACT
NC-0094	1/9/2002	GenPower Earleys, LLC	CTG/HRSG	Good Combustion Practices	9	ppm	BACT
NC-0095	5/28/2002	Mirant Gastonia		Good Combustion Practices	9	ppm	BACT
SC	5/28/2002	Jasper County Generating Facility		Good Combustion Practices	9	ppm	
VA-0287	12/1/2003	James City Energy Park		Good Combustion Practices	9	ppm	BACT
VA-0289	2/5/2004	Duke Energy Wythe, LLC		Good Combustion Practices	9	ppmvd	BACT
AL-0185	7/12/2002	Barton Shoals Energy, LLC		Good Combustion Practices	10	ppm	BACT
FL-0202	8/17/1992	Orlando Cogen	CTG	Combustion Controls	10	ppmv	BACT
FL-0244	4/16/2003	FPL Martin		Good Combustion Practices	10	ppmvd	BACT
FL-0245	4/15/2003	FPL Manatee - Unit 3		Good Combustion Practices	10	ppmvd	BACT
FL-0256	9/8/2003	FPC - Hines Energy Complex		Good Combustion Practices	10	ppmvd	BACT
MI-0366	10/10/2002	Berrien Energy LLC		Oxidation Catalyst	10	ppmvd	BACT
MN-0053	7/15/2004	Fairbault Energy Park		Good Combustion Practices	10	ppmvd	BACT
MO-0049	8/19/1999	Kansas City Power & Light	CTG/HRSG	Oxidation Catalyst	10	ppmv	BACT
MO-0056	3/30/1999	Associated Electric Cooperative, Inc.	CTG	Good Combustion	10	ppmv	BACT
OK	3/24/1999	Chouteau Power Plant	CTG/HRSG	Combustion Controls	10	ppm	BACT
OK-0036	12/10/2001	Stephens Energy Facility	CTG/HRSG	Good Combustion Practices	10	ppmv	BACT
OK-0043	10/22/2001	Webers Falls Energy Facility	CTG	Combustion Controls	10	ppmv	BACT
OK-0090	3/21/2003	Duke Energy Stephens, LLC		Combustion Controls	10	ppm	BACT
PA-0160	10/10/2000	Calpine Construction Finance Co.	CTG/HRSG	Good Combustion Practices	10	ppmv	BACT
PA-0226	4/9/2002	Limerick Partners, LLC	CTG/HRSG	Good Combustion Practices	10	ppm	BACT
VA-0262	12/6/2002	Mirant Airside Industrial Park	CTG/HRSG	Good Combustion Practices	10.3	ppmvd	BACT

RBLC ID	Permit Date	Facility	Process	Control Technology	Emission Limit	Emission Limit Unit	Basis
NC-0101	1/23/2004	Forsyth Energy Projects		Good Combustion Practices	11.6	ppm	BACT
GA-0101	10/23/2002	Murray Energy Facility		Good Combustion Practices	12	ppm	BACT
FL-0239	3/27/2002	Jacksonville Electric Auth - Brandy Branch		Good Combustion Practices	12.21	ppmvd	BACT
MS-0055	6/24/2002	El Paso Merchant Energy CO.		Good Combustion Practices	13.8	ppmv	BACT
OK-0096	6/6/2003	Redbud Power Plant		Good Combustion Practices	17.2	ppmvd	BACT
VA-0256	1/20/2002	Tenaska Fluvanna		Good Combustion Practices	21	ppmvd	BACT
AR-0051	4/1/2002	Duke Energy - Jackson Facility		Good Operating Practices	23.6	ppm	BACT
TX-0384	12/13/2002	Steag (Brazos Valley)		Good Combustion Practices	24	ppm	BACT
LA-0157	3/8/2002	Perryville Power Station		Good Operating Practices	25	ppm	BACT
TN-0144	2/1/2002	Haywood Energy Center (Calpine)		Good Combustion Practices	28.3	ppm	BACT
WY-0061	4/4/2003	Black Hills Corp - Neil Simpson Two		Good Combustion Practices	37.2	ppmvd	BACT
MS-0059	9/24/2002	Pike Generation Facility		Good Combustion Practices	40	ppmv	BACT
OK-0055	2/12/2002	Mustang Energy Project		Combustion Controls	40	ppm	BACT
NE-0023	5/29/2003	Nebraska Public Power District - Beatrice		Oxidation Catalyst	18.4	lb/hour	BACT
OH-0264	5/23/2004	Norton Energy Storage, LLC			23	lb/hour	BACT
MI-0362	4/21/2003	Midland Cogeneration Venture LP		Good Combustion Practices	26	lb/hour	BACT
VA-0255	11/18/2002	VA Power - Possum Point			32	lb/hour	BACT
AZ-0034	2/15/2001	Harquahala Generating Project	CTG/HRSG	Oxidation Catalyst	37	lb/hour	BACT
NM-0044	6/27/2004	Clovis Energy Fac - Duke Energy Curry LLC		Good Combustor Design	37.6	lb/hour	BACT
VA-0260	5/1/2002	Henry County Power		Good Combustion Practices	41.4	lb/hour	BACT
MI-0363	1/7/2003	Bluewater Energy Center LLC		Catalytic Afterburner	41.7	lb/hour	BACT
TX-0234	1/8/2002	Edinburg Energy Limited Partnership	CTG		43	lb/hour	BACT
LA-0120	2/26/2002	Shell Chemical LP - Geismar Plant		Good Combustion Practices	44	lb/hour	BACT
TX-0391	12/20/2002	Oxy Cogeneration Facility - Oxy Vinyls LP		Good Combustion Practices	64.3	lb/hour	BACT
TX-0374	3/24/2003	Chocolate Bayou - BP Amoco Chemical		Good Combustion Practices	66.81	lb/hour	BACT
TX-0352	12/31/2002	Brazos Valley Electric Generating Facility		Good Combustion Control	92.4	lb/hour	BACT
TX-0388	2/12/2002	Sand Hill Energy Center - Austin Electric			98.2	lb/hour	BACT
TX-0407	12/6/2002	Steag-Stearne	CTG/HRSG	Good Combustion Practices	109.4	lb/hour	BACT
TX-0350	1/31/2002	Ennis Tractebel Power	CTG/HRSG	None	124	lb/hour	BACT
MT-0019	6/7/2002	Continental Energy Serv - Silver Bow Gen			139.9	lb/hour	Other
TX-0411	3/26/2002	Amelia Energy Center		Good Combustion Practices	208	lb/hour	

4. Volatile Organic Compounds (VOC)

The proposed combustion turbines and duct burners are natural gas-fired combustion units. The VOC emissions from natural gas-fired combustion sources are the result of two possible formation pathways: incomplete combustion, and recombination of the products of incomplete combustion. Complete combustion is a function of three key variables: time, temperature, and turbulence. Once the combustion process begins, there must be enough time at the required combustion temperature to complete the process, and during combustion there must also be enough turbulence or mixing to ensure that the fuel gets enough oxygen from the combustion air.

Combustion systems with poor control of the fuel to air ratio, poor mixing, and/or insufficient time at combustion temperatures have higher VOC emissions than those with good controls. The proposed turbines and duct burners incorporate state-of-the-art combustion technology, and both are designed to achieve high combustion efficiencies. As a result, the proposed combustion equipment has very low expected VOC emission rates.

The two most prevalent components of natural gas, methane (~94% by volume) and ethane (~4% by volume), are not defined as VOCs. The remaining portions of natural gas are propane and trace quantities of higher molecular weight hydrocarbons, all of which are nearly 100% combusted. The high energy efficiency of turbines and duct burners and low fraction of VOCs in natural gas result in a very low VOC emissions rate for the proposed new units. Additionally, the recombination of products of incomplete combustion is unlikely in well controlled turbine/duct burner systems because the conditions required for recombination are not present.

The applicant considered $SCONO_x$, catalytic oxidation, and good combustion controls as possible control technologies. As noted previously, $SCONO_x$ can control NO_x, CO, and VOC, and the additional control of VOC was incorporated into the cost analysis. $SCONO_x$ was rejected for economic considerations and is not considered further. An oxidation catalyst represents the most stringent control option, thus, no further analysis of control technologies is required. Table 10 presents a comparison of the control systems considered by the applicant and previously permitted VOC control systems taken from the RBLC.

The applicant is proposing the use of an oxidation catalyst, in addition to combustion controls, to reduce VOC emissions to 2.6 ppmvd at 15% O_2 with and without duct firing and power augmentation, on a 3-hour average. Upon review of the data, ADEQ concurs with and approves the applicant's BACT proposal.

Table 10. CTG/HRSG BACT Comparison for VOC

RBLC ID	Permit Date	Facility	Process	Control Technology	Emission Limit	Emission Limit Unit	Basis
WI-0174	9/20/00	Badger Generating Co, LLC	CTG	Oxidation Catalyst	1.2	ppmv	LAER
NJ-0043	3/28/02	Liberty Generating Station	CTG/HRSG	Oxidation Catalyst	1.7	ppmv	BACT
PA-0184	10/10/00	Calpine Construction Finance Co, LP	CTG	Oxidation Catalyst	1.8	ppmv	BACT
FL-0216	6/4/01	FPC - Hines Energy Complex, PowerBk-2	CTG	Combustion Controls	2	ppmv	BACT
PA-0191	4/18/02	Limerick Partners, LLC	CTG	Oxidation Catalyst	2.4	ppmv	OTHER
AZ	3/4/03	Bowie Power Station	CTG/HRSG	Oxidation Catalyst	2.6	ppmv	BACT
AZ-0034	2/15/01	Harquahala Generating Project	CTG/HRSG	Oxidation Catalyst	2.8	ppmv	BACT
RI-0019	5/3/00	Reliant Energy Hope Generating Facility	CTG/HRSG	Oxidation Catalyst	2.9	ppmv	BACT
FL-0124	11/22/99	Oleander Power Project	CTG	Good Combustion	3	ppmv	BACT
PA-0192	10/20/01	Lower Mount Bethel Energy, LLC	CTG	Oxidation Catalyst	3	ppmv	LAER
MA-0025	8/4/99	ANP Bellingham Energy Co	CTG	Oxidation Catalyst	3.5	ppmv	LAER
MA-0024	4/16/99	ANP Blackstone Energy Co	CTG	Oxidation Catalyst	3.5	ppmv	BACT
MI-0267	6/7/01	Renaissance Power, LLC	CTG/HRSG	Oxidation Catalyst	4	ppmv	BACT
MI-0327	12/2/01	Indeck-Niles, LLC	CTG/HRSG	NG	4	ppmv	BACT
MI-0303	7/26/01	Midland Cogeneration	CTG/HRSG	Oxidation Catalyst	4.2	ppmv	BACT
SC-0061	4/9/01	Columbia Energy, LLC	CTG	Good Combustion	4.5	ppmv	BACT
AZ-0033	3/22/01	Mesquite Generating Station	CTG/HRSG	Oxidation Catalyst	5.2	ppmv	BACT
AL-0185	7/12/02	Barton Shoals Energy	CTG/HRSG	Good combustion	5.3	ppmv	BACT
OK-0046	5/17/01	Thunderbird Power Plant	CTG/HRSG	Combustion Controls	7	ppmv	BACT
SC-0063	7/3/01	Genpower Anderson LLC	CTG/HRSG	Good Combustion	7	ppmv	BACT
TX-0234	1/8/02	Edinburg Energy Limited Partnership	CTG	NG	9	ppmv	BACT
IN-0085	6/7/01	PSEG Lawrenceburg Energy Facility	CTG/HRSG	Good Combustion	3	lb/hr	BACT
IN-0086	5/9/01	Mirant Sugar Creek LLC	CTG/HRSG	Good Combustion	3.7	lb/hr	BACT
OK-0044	8/16/01	Smith Pocola Energy Project	CTG/HRSG	Good Combustion	0.0016	lb/MMBtu	BACT
AR-0043	2/27/01	Pine Bluff Energy LLC	CTG/HRSG	Good Combustion	0.0017	lb/MMBtu	BACT
PA-0188	3/28/02	Fairless Energy LLC	CTG	Oxidation Catalyst	0.002	lb/MMBtu	OTHER
AL-0179	10/3/01	Tenaska Talladega Generating Station	CTG/HRSG	Good Combustion	0.0078	lb/MMBtu	BACT

5. Sulfur Dioxide (SO_2)

The proposed combustion turbines and duct burners will be designed and operated to minimize emissions and will be fired solely with natural gas, which is inherently low in sulfur. Sulfur dioxide is formed during combustion due to the oxidation of the sulfur in the fuel. Add-on control devices (e.g., scrubbers) are typically used to control emissions from combustion sources firing higher sulfur fuels, such as coal. Flue gas desulfurization is not appropriate for use with low sulfur fuel, and is not considered for this project, because the realizable emission reduction is far too small for this option to be cost-effective.

The use of natural gas is proposed as BACT for SO_2. As discussed under the NSPS section, SO_2 emissions will be below the regulatory limits required by Subpart GG (there are no SO_2 requirements in Subpart Da for natural gas fired units). Table 11 presents a comparison of the SO_2 BACT limits proposed by the applicant and previously permitted SO_2 limits taken from the RBLC. As shown in Table 11, there is no precedent for use of post-combustion control of SO_2 on combined cycle units.

B. Auxiliary Boiler

The proposed project includes one 50 MMBtu/hr auxiliary boiler. The limitation on the hours of operation (i.e., 450 hours per year) results in minimal emissions. The applicant is proposing the use of low-NO_x burners for NO_x control, and combustion controls and the use of natural gas to control CO, VOC, PM_{10}, and SO_2.

The emissions from the auxiliary boiler are so low that potential emission reductions from controls are not cost-effective. As demonstrated in the BACT analysis for NO_x, the largest emission reduction is 0.52 tpy (considering a 98.6% reduction). At such a reduction, the capital cost of a control system would need to be quite inexpensive to be cost-effective, and is below the cost of available controls. Consequently, the application of control technologies are not cost-effective and low-NO_x burners are determined as BACT for NO_x.

Emissions of CO and VOC are also low. As a result, an add-on control device such as an oxidation catalyst would not be cost-effective. As with the combined-cycle units, no add-on control devices have been identified for the control of PM_{10} or SO_2 from the auxiliary boiler. Combustion controls and the use of natural gas are considered BACT for CO, VOC, PM_{10}, and SO_2 from the auxiliary boiler.

C. Cooling Towers

Particulates are emitted from cooling towers when small droplets of cooling water, called drift, are emitted and evaporate. The dissolved and suspended materials in the drift can become airborne particles when the water around them evaporates. The size distribution of the emitted particulates includes particles in both the PM and PM_{10} range.

Table 11. CTG/HRSG BACT Comparison for SO_2

RBLC ID	Permit Date	Facility	Process	Control Technology	Emission Limit	Emission Limit Unit	Basis
OR-0035	1/16/02	Port Westward - Portland General Electric	CTG	Natural Gas	0.80	% by weight S in Fuel	BACT
OR-0040	3/12/03	Klamath Generation LLC - Pacific Power	CTG/HRSG	Natural Gas	0.80	% by weight S in Fuel	BACT
MI-0361	1/30/03	South Shore Power LLC	CTG/HRSG	Pipeline Quality Natural Gas	0.20	gr/100 scf	BACT
MI-0362	4/21/03	Midland Cogeneration Venture LP	CTG/HRSG	Natural Gas	0.20	gr/100 scf	BACT
VA-0262	12/6/02	Mirant Airside Industrial Park	CTG/HRSG	Low Sulfur Fuel	0.80	gr/100 scf	BACT
CA-0997	9/1/03	Sacramento Municipal Utility District	CTG	Low Sulfur Natural Gas	1.00	gr/100 scf	LAER
FL-0245	4/15/03	FPL Manatee - Unit 3	CTG/HRSG	Low Sulfur Fuel	2.00	gr/100 scf	BACT
TX-0391	12/20/02	Oxy Cogeneration Facility - Oxy Vinyls LP	CTG/HRSG	Sulfur Limit in Fuel less than 5 grains/100 dscf	0.60	lb/hour	BACT
MN-0053	7/15/04	Fairbault Energy Park	CTG/HRSG	Low Sulfur Fuel	0.80	gr/dscf	BACT
OK	3/24/99	Chouteau Power Plant	CTG/HRSG	Use of Natural Gas	1.00	lb/hour	
NV-0033	8/19/04	El Dorado Energy, LLC	CTG	Use of Natural Gas	1.03	lb/hour	BACT
CA	5/21/01	Three Mountain Power	CTG/HRSG		1.20	lb/hour	BACT-CA
CA	3/1/01	Mountainview Power Project	CTG/HRSG		1.40	lb/hour	BACT-CA
CA	2/1/02	Delta Energy Center	CTG/HRSG		1.50	lb/hour	BACT-CA
TX-0388	2/12/02	Sand Hill Energy Center - Austin Electric		Low Sulfur Fuel	1.60	lb/hour	BACT
VA-0255	11/18/02	VA Power - Possum Point			2.08	lb/hour	BACT
VA-0289	2/5/04	Duke Energy Wythe, LLC		Sulfur in Fuel Limited to 0.3 gr/100 dscf	2.08	lb/hour	BACT
AZ-0033	3/22/01	Mesquite Generating Station	CTG/HRSG	Use of Natural Gas	2.10	lb/hour	BACT
OK	1/21/00	Oneta Generating Station	CTG/HRSG	Use of Natural Gas	2.50	lb/hour	BACT
OH-0264	5/23/04	Norton Energy Storage, LLC	CTG	Use of Natural Gas	2.55	lb/hour	BACT
CA	10/1/00	Blythe Energy	CTG/HRSG		2.70	lb/hour	BACT-CA
CA	3/1/01	Western Midway Sunset Power Project	CTG/HRSG		3.80	lb/hour	BACT-CA

RBLC ID	Permit Date	Facility	Process	Control Technology	Emission Limit	Emission Limit Unit	Basis
CA	3/1/01	Western Midway Sunset Power Project	CTG/HRSG		3.90	lb/hour	BACT-CA
TX-0234	1/8/02	Edinburg Energy Limited Partnership	CTG		4.00	lb/hour	BACT
IN-0086	5/9/01	Mirant Sugar Creek LLC	CTG/HRSG	Low Sulfur Natural Gas	4.20	lb/hour	BACT
MA-0025	8/4/99	ANP Bellingham	CTG	Use of Natural Gas	4.20	lb/hour	BACT
NM-0044	6/27/04	Clovis Energy - Duke Energy Curry LLC	CTG/HRSG	Pipeline Quality Natural Gas	4.30	lb/hour	BACT
IN-0114	7/24/02	Mirant Sugar Creek LLC	CTG/HRSG	Low Sulfur Natural Gas	4.40	lb/hour	BACT
TX-0381	1/31/03	Ennis Tractebel Power		Pipeline Natural Gas	4.80	lb/hour	BACT
WV-0014	12/18/01	Panda Culloden Generating Station	CTG/HRSG	Use of Natural Gas	5.40	lb/hour	BACT
AZ-0034	2/15/01	Harquahala Generating Project	CTG/HRSG	Use of Natural Gas	5.80	lb/hour	BACT
MA	5/7/00	Cabot Power Corporation	CTG/HRSG	Use of Natural Gas	5.90	lb/hour	BACT
SC-0063	7/3/01	Genpower Anderson LLC		Low Sulfur Fuel	6.00	lb/hour	BACT
TX-0407	12/6/02	Steag-Stearne	CTG/HRSG	Pipeline Natural Gas	7.10	lb/hour	BACT
TX-0352	12/31/02	Brazos Valley Electric Generating Facility	CTG/HRSG	Sweet Natural Gas	7.20	lb/hour	BACT
IN-0085	6/7/01	PSEG Lawrenceburg Energy Facility	CTG/HRSG	Low Sulfur Natural Gas	11.00	lb/hour	BACT
VA-0287	12/1/03	James City Energy Park	CTG/HRSG	Low Sulfur Fuel	11.40	lb/hour	BACT
TN-0144	2/1/02	Haywood Energy Center (Calpine)	CTG/HRSG	Low Sulfur Fuel	11.70	lb/hour	BACT
ME	9/14/98	Champion Intl Corp. & Champ. Clean Energy	CTG/HRSG		12.00	lb/hour	BACT
MS	3/27/01	Caledonia Power LLC	CTG/HRSG		12.00	lb/hour	BACT
TX-0374	3/24/03	Chocolate Bayou - BP Amoco Chemical Co		Low Sulfur Fuel	12.66	lb/hour	Other
TX-0411	3/26/02	Amelia Energy Center		Low Sulfur Fuel	13.60	lb/hour	
MS-0051	11/13/01	LSP - Batesville Generation Facility	CTG/HRSG	Natural Gas	15.00	lb/hour	
MS-0059	9/24/02	Pike Generation Facility		Low Sulfur Fuel	15.60	lb/hour	BACT
OH-0248	9/24/02	Lawrence Energy - Calpine Corporation		Burning Natural Gas	16.10	lb/hour	BACT
MS-0055	6/24/02	El Paso Merchant Energy CO.		Low Sulfur Fuel	32.20	lb/hour	BACT
OH-0268	3/26/02	Lima Energy Company	CTG/HRSG	Solvent-Based Absorption Technology w/Tail Gas Recirculation Prior to Combustion	38.60	lb/hour	BACT
AR-0043	2/27/01	Pine Bluff Energy LLC	CTG/HRSG	Low Sulfur Fuels	0.001	lb/mmBtu	BACT
NC-0086	1/10/02	Fayetteville Generation			0.001	lb/mmBtu	BACT

RBLC ID	Permit Date	Facility	Process	Control Technology	Emission Limit	Emission Limit Unit	Basis
NC-0101	1/23/04	Forsyth Energy Projects		Low Sulfur Fuel	0.001	lb/mmBtu	BACT
AL-0168	1/12/01	GenPower Kelley LLC	CTG/HRSG		0.002	lb/mmBtu	BACT
PA-0188	3/28/02	Fairless Energy LLC	CTG	Low Sulfur Fuel	0.002	lb/mmBtu	Other
PA-0196	8/7/01	SWEC-Falls Township	CTG		0.002	lb/mmBtu	Other
MI-0357	2/4/03	Kalkaska Generating LLC		Use of Low Sulfur Fuel	0.003	lb/mmBtu	BACT
OK-0096	6/6/03	Redbud Power Plant		Low Sulfur Fuel	0.003	lb/mmBtu	BACT
AZ	3/4/03	Bowie Generating Station	CTG/HRSG	Natural Gas	0.004	lb/MMBtu	BACT
NJ-0043	3/28/02	Liberty Generating Station	CTG/HRSG	Use of Natural Gas	0.004	lb/mmBtu	Other
OK-0046	5/17/01	Thunderbird Power Plant	CTG/HRSG	Natural Gas	0.005	lb/mmBtu	BACT
RI-0019	5/3/00	Reliant Energy Hope Gen. Facility	CTG/HRSG	Clean Fuel - Natural Gas	0.005	lb/mmBtu	BACT
OK-0056	2/12/02	Horseshoe Energy Project		Low Sulfur Fuel	0.006	lb/mmBtu	BACT
PA-0160	10/10/00	Calpine Construction Finance Co.	CTG	Good Comb / Sulfur Content	0.006	lb/mmBtu	BACT
IN-0087	6/6/01	Duke Energy, Vigo LLC	CTG/HRSG	Good Comb / Natural Gas	0.006	lb/mmBtu	BACT
OK-0051	10/1/99	Green County Energy Project	CTG/HRSG	Use of Natural Gas	0.006	lb/mmBtu	BACT
OK-0090	3/21/03	Duke Energy Stephens, LLC		Pipeline Quality Natural Gas	0.006	lb/mmBtu	BACT
VA-0260	5/1/02	Henry County Power		Low Sulfur Fuel/Good Comb	0.006	lb/mmBtu	BACT
AL-0185	7/12/02	Barton Shoals Energy, LLC	CTG/HRSG	Natural Gas Only	0.007	lb/mmBtu	BACT
VA-0261	9/6/02	CPV Cunningham Creek			0.012	lb/mmBtu	BACT
OK-0044	8/16/01	Smith Pocola Energy Project	CTG/HRSG	Use of Natural Gas	0.216	lb/mmBtu	BACT
PA-0192	10/20/01	Lower Mount Bethel Energy, LLC	CTG		0.003	ppmv	LAER
VA-0256	1/20/02	Tenaska Fluvanna		Use of Natural Gas	0.300	ppmvd	BACT
WA-0291	1/3/03	Wallula Power - Newport Northwest		Natural Gas	0.350	ppmvd	BACT
PA-0226	4/9/02	Limerick Partners, LLC	CTG	Low Sulfur Fuel	0.800	ppmv	Other
WA-0299	4/17/03	Sumas Energy 2 - NESCO		Low Sulfur Fuel	1.000	ppmvd	BACT
PA-0223	1/30/02	Duke Energy Fayette, LLC		Low Sulfur Fuel	1.600	ppmvd	BACT
OK-0055	2/12/02	Mustang Energy Project		Natural Gas	15.550	tons/year	BACT
MI-0365	1/28/03	Mirant Wyandotte LLC		Use of Sweet Natural Gas	53.400	tons/year	BACT
MI-0366	10/10/02	Berrien Energy LLC		Pipeline Quality Natural Gas	174.70	tons/year	BACT
MI-0363	1/7/03	Bluewater Energy Center LLC		Use of Natural Gas	177.00	tons/year	BACT
FL-0241	1/17/02	CPV Cana Power Generation Facility		Clean Fuel, Sulfur Fuel Limit			BACT
FL-0244	4/16/03	FPL Martin		Nat. Gas, Sulfur Fuel Limit			BACT
FL-0256	9/8/03	FPC - Hines Energy Complex		Low Sulfur Fuel			BACT

There are two primary factors that control the amount of PM_{10} from the cooling tower: the total dissolved solids (TDS) in the cooling tower water and the droplet drift rate. A droplet drift rate of 0.0005 percent (achieved through the use of high efficiency drift eliminators on the cooling tower) was determined to represent BACT for the cooling towers. The BACT limit is based on vendor guarantees and is consistent with the most stringent limits listed in the RBLC.

The TDS is the second parameter affecting PM_{10} from the cooling towers. The TDS proposed by the applicant, 12,000 parts per million (ppm), is based on ninety cycles of concentration. This limit is a balance between the need to keep the TDS low and the need to minimize water usage (which forces the TDS higher). The 12,000 ppm TDS limit is established as a permit condition, as well as the compliance demonstration requirements to perform monthly TDS laboratory analyses and daily measurements of conductivity (this is a surrogate parameter directly related to TDS concentrations).

ADEQ also requested the applicant consider a dry, air-cooled condenser in lieu of a wet cooling tower as the top control option in its cooling tower BACT analysis. The applicant provided cost data for such a dry system that demonstrated that the technology was not economically feasible when compared to a wet cooling tower. Consequently, the Department concludes that the high efficiency drift eliminators with an efficiency of 0.0005 percent are BACT for PM_{10} for the cooling towers.

D. Fire Water Pumps and Emergency Generators

The proposed facility includes two diesel fire water pumps and two emergency generators, which will be operated only for testing/maintenance or emergencies. The limitation on the hours of operation (i.e., 120 hours per year each) results in minimal emissions. As a result, BACT for the engines was determined to be good combustion control as provided by modern engine control systems and the use of diesel fuel with a sulfur content of 0.05%.

VI. MONITORING REQUIREMENTS

A. Compliance Assurance Monitoring (CAM)

Pursuant to 40 CFR 64.2(b)(iii), the subject facility is not subject to CAM for NO_x because it is subject to Acid Rain Program requirements, and is not subject to CAM for CO because the facility will install a CEMS to measure CO emissions.

B. Combined Cycle Systems With and Without Duct Firing and Power Augmentation

The Combined Cycle Systems may be operated in combined cycle operation and may only burn pipeline quality natural gas.

PM: The units are subject to a PM_{10} emission limitation resulting from the application of BACT. Verification through annual performance testing will fulfill the requirements for periodic monitoring. Emissions will be determined using the performance test results and monitored fuel usage data.

Opacity: The Combined Cycle Systems are subject to the opacity standard of 10% as is consistent with previous permitting projects in the State (i.e., Griffin Energy). Natural gas is a clean burning fuel and operation of these types of units generally indicate that opacity problems are rare.

NO_x: The units are subject to a NO_x emissions limitation resulting from the application of BACT. The source is required to operate, certify, maintain, and calibrate compliance CEMS for NO_x. The CEMS will comply with the applicable requirements of 40 CFR Part 75. A Relative Accuracy Test Audit (RATA) is required annually for the monitors. The source is also required to develop an Operations and Maintenance plan for the SCR system.

CO: The units are subject to a CO emissions limitation resulting from the application of BACT. The source is required to operate, certify, maintain, and calibrate compliance CEMS for CO. The CEMS will comply with the applicable provisions of 40 CFR Part 60 and 40 CFR Part 75. A RATA is required annually for the monitors.

SO_2: The units are subject to a limit of 0.75 grains of sulfur/100 dscf in the natural gas and a limit of 8.7 pounds of SO_2 per hour. This limit will be demonstrated by the Permittee maintaining a vendor-provided copy of that part of the Federal Energy Regulatory Commission (FERC)-approved tariff agreement that contains the sulfur content and the lower heating value of the pipeline quality natural gas. Emissions will be determined using the sulfur content in the fuel and monitored fuel usage data.

VOC: The units are subject to a VOC emissions limitation due to the additional benefits resulting from the application of BACT to control CO emissions. Every two years, the Permittee shall verify through performance testing that the units meet the limits, this will fulfill the requirements for periodic monitoring. Emissions will be determined using the performance test results and monitored fuel usage data.

Ammonia: The units are subject to an ammonia slip emission limit. The source is required to operate, certify, maintain, and calibrate on each SCR unit an ammonia CEMS or ammonia parametric emissions monitoring system (PEMS) based on ammonia flow rate and NO_x emissions data (as approved by the Department). Flow and Diluent: As per 40 CFR Part 75, fuel flow meters are required on each fuel line to monitor the unit-specific fuel flow to the combustion turbines and duct burners. O_2 (or CO_2) diluent gas monitors are required on each combined cycle system. The monitors will comply with the applicable provisions of 40 CFR Part 60 (Appendices B and F) and 40 CFR Part 75.

VII. TESTING REQUIREMENTS

Performance testing is one component used to demonstrate compliance with the emission rates in the permit. Specifications regarding the test plan, sampling facilities, and reports are included in the General Provisions (Attachment A) of the permit. Test methods are specified in the permit and testing will be performed at full load and at reduced load conditions.

A. Combined Cycle Systems with Duct Firing and Power Augmentation

Bowie is required by the permit to perform initial performance tests for NO_x, CO, VOC, PM_{10}, and SO_2 with both duct firing and power augmentation. Annual stack testing for NO_x and CO is not specified separately because annual testing will be conducted as part of the RATA for the CEMS. Performance testing for ammonia at full load with duct firing and power augmentation will be conducted initially and every two years thereafter. Catalyst life expectancy for SCR is typically given as three years. Performing a stack test every two years will determine if there is early catalyst degradation. Annual tests for PM_{10} and VOC will alternate between full load with duct firing and power augmentation and the no duct firing or power augmentation case. The initial performance test for SO_2 will be used to demonstrate compliance with the 8.7 pounds of SO_2 per hour emission limitation.

B. Combined Cycle Systems with Duct Firing without Power Augmentation

Bowie is required to perform initial performance tests for NO_x, SO_2, and PM_{10} in accordance with 40 CFR 60.48a(b), (c), and (d). Initial performance tests for CO and VOC are also required upon start-up. Annual stack testing for NO_x and CO is not specified separately because annual testing will be conducted as part of the RATA for the CEMS.

C. Combined Cycle Systems without Duct Firing or Power Augmentation

Bowie is required to perform initial performance tests for SO_2 and the nitrogen and sulfur content of the fuel in accordance with 40 CFR 60.335. An initial performance test upon start-up is required for NO_x, CO, PM_{10}, and VOC. Annual stack testing for NO_x and CO is not specified separately because annual testing will be conducted as part of the RATA for the CEMS. Annual tests for PM_{10} and VOC will alternate between full load with duct firing and power augmentation and the no duct firing or power augmentation case.

D. Auxiliary Boilers

Bowie is required to perform an initial performance test for NO_x, CO, VOC, and PM_{10} emissions from the auxiliary boiler.

VIII. IMPACTS TO AMBIENT AIR QUALITY

A. Ambient Air Quality Impacts Analysis

1. General

As noted in Section IV, the PSD ambient air quality analysis requirements are applicable to the Bowie Power Station project for the pollutants NO_x, CO, SO_2, and PM_{10}. EPA's guidance for performing PSD air quality analyses is set forth in Chapter C of the October 1990 New Source Review Workshop Manual, as well as in 40 CFR Part 51 Appendix W. The modeling analysis is performed in two steps: a "facility-only" significant impact analysis, and if required a cumulative impact or "multi-source" analysis. The preliminary analysis estimates ambient concentrations resulting from the proposed project for pollutants that trigger PSD requirements. The results of the significant impact modeling determine whether the Applicant must perform a full impact analysis. If the ambient impacts are greater than the Significant Impact Levels (SILs, see Table 12), then the extent of the Significant Impact Area (SIA) of the proposed project is determined.

The full impact analysis expands the "facility-only" significant impact analysis by considering emissions from both the proposed project as well as other sources in the SIA (and other sources outside of the SIA that cause significant impacts in the proposed source's SIA). The results from the full impact analysis are used to demonstrate compliance with NAAQS and PSD increments. The source inventory for the cumulative NAAQS analysis includes all nearby sources that have significant impacts within the proposed source SIL, while the source inventory for the cumulative PSD analysis is limited to increment-effecting sources (new sources and changes to existing sources that have occurred since the applicable increment baseline date).

The full impact analysis is limited to receptor locations within the proposed project's SIA. The modeling results from the NAAQS cumulative impact analysis are added to representative ambient background concentrations and the total concentrations are compared to the NAAQS. Conversely, the modeled air quality impacts for all increment-consuming sources are directly compared to the PSD increments to determine compliance (without consideration of ambient background concentrations).

According to EPA guidance, if the cumulative impact analysis demonstrates violations of any NAAQS or PSD increment, the proposed facility can still be permitted if it can be demonstrated that the facility does not result in ambient impacts that exceed the SIL at the same time and location of any modeled violation. In other words, the facility must demonstrate that it would not "significantly contribute" to any modeled violation.

Table 12. Ambient Air Quality Standards and PSD Class II Increments ($\mu g/m^3$)

Pollutant	**NO_x**	**CO**		**SO_2**			**PM_{10}**	
Averaging Period	Annual	1-hour	8-hour	3-hour	24 hour	Annual	24-hour	Annual
PSD Class II Increment Level	25	NA	NA	512	91	20	30	17
Class II Wilderness Area SIL	1	2000	500	25	5	1	5	1
Monitoring Exception Level	14	NA	575	NA	13	NA	10	NA
NAAQS	100	40,000	10,000	1300	365	80	150	50

2. Modeling Methodology

a. Source Data for the Project

The PSD ambient air quality analysis requirements are applicable for the pollutants NO_x, CO, SO_2 and PM_{10}.

A detailed load-screening analyses was first conducted to determine which operating scenarios resulted in maximum ambient impacts for each pollutant. These scenarios included 100% load operations (with and without duct firing and power augmentation), 75% load operations, and a 50% startup/shutdown scenario for 5 temperature ranges. The final range of combinations assessed with modeling analyses for load screening are listed in Table 13 below. The final load conditions used in the modeling analyses are listed in Table 14.

b. NAAQS and PSD Increment Inventory

Other sources within 100 kilometers are generally modeled as part of the NAAQS inventory. This is necessary only when the maximum modeled impacts from the proposed facility exceed the SIL for any criteria pollutant and averaging period.

Table 13. Load Screening Analyses Scenarios

Pollutant	**Averaging Period**	**Ambient Temp**	**Load %**	**Operating Scenarios**	**Comments**
All	Annual	59 °F	100%	With and without duct firing and power augmentation	Design capacity (full load conditions)
NO_x CO SO_2 HAPS	1,2,and 4 hr 1 and 8 hr 1 and 3 hr 1 and 24 hr	All	All	With and without duct firing and power augmentation	
PM_{10} NO_x SO_2	24 hr 24 hr 24 hr	All	Average of 50%,75%, and 100%; 100%	With and without duct firing and power augmentation	

Table 14. Stack Characteristics used in Final Modeling Analyses

Pollutant/ Averaging Period	Stack Height (m)	Gas Exit Temperature (K)	Gas Exit Velocity (m/s)	Diameter (m)	Comments
All/Annual	39.6	362	20.5	5.5	100% load/with duct firing
All/1-8 hr	39.6	349.3	12.5	5.5	50% load/turbines only at 59°F
All/24 hr	39.6	358.3	15.8	5.5	Average 50/75/100% loads Turbines only

c. Computer Model Used

The typical refined model used in air quality analyses is the Industrial Source Complex Short Term Model (ISCST3). The model was approved for use by ADEQ after consultation and approval from EPA Region IX in previously submitted modeling protocol (Wind River, December 2001).

For modeling Class I impacts greater than 50 kilometers away, the applicant used the CALPUFF model, as discussed in the modeling protocol and the revised Air Quality Modeling Report, (Wind River, December 20012001).

d. Receptor Grid

For purposes of demonstrating compliance with the PSD increment, the NAAQS and the Arizona Ambient Air Quality Guidelines (AAAQGs), a receptor grid was created with sufficient density to determine the maximum model-predicted impact within the surrounding ambient air (inclusive of process area where applicable). Receptor elevations were derived from the United States Geological Service (USGS) Digital Elevation Model (DEM) data. The finest grid spacing was set at 25 meters for the project boundary and any additional areas where maximum impacts are predicted to occur.

Table 15. Source Emissions and Stack Parameters for Bowie Power Station Sources

Source ID	UTM Easting (m)	UTM Northing (m)	Elevation (m)	NO_x (tpy)	CO (g/s)	SO_2 (g/s)	PM_{10} (g/s)	Stack Ht (m)	Temp (K)	Velocity (m/s)	Diameter (m)
Turbine 1	641450	3581683	1134	76.5	31.5	1.1	2.77	39.6	358	15.8	5.5
Turbine 2	641462	3581639	1134	76.5	31.5	1.1	2.77	39.6	358	15.8	5.5
Turbine 3	641539	3581350	1134	76.5	31.5	1.1	2.77	39.6	358	15.8	5.5
Turbine 4	641551	3581306	1134	76.5	31.5	1.1	2.77	39.6	358	15.8	5.5
Fire Pump (north)	641509	3581589	1134	0.5	0.22	0.002	0.01	10.7	659	.001	27.6a
Fire Pump (south)	641559	3581405	1134	0.5	0.22	0.002	0.01	10.7	659	.001	26.6[a]
Emergency Generator (north)	641410	3581577	1134	1.6	0.90	0.01	0.01	16.8	787	.001	62.1[a]
Emergency Generator (south)	641463	3581376	1134	1.6	0.90	0.01	0.01	16.8	787	.001	62.1[a]
Auxiliary Boiler	641422	3581488	1134	0.6	0.50	0.04	0.05	13.7	478	22.1	0.46
North Cooling Tower Cell 1	641509	3581657	1134	NA	NA	NA	0.025	15.5	294	15.8	8.5
Cell 2	641513	3581646	1134	NA	NA	NA	0.025	15.5	294	15.8	8.5
Cell 3	641516	3581634	1134	NA	NA	NA	0.025	15.5	294	15.8	8.5
Cell 4	641519	3581623	1134	NA	NA	NA	0.025	15.5	294	15.8	8.5
Cell 5	641522	3581611	1134	NA	NA	NA	0.025	15.5	294	15.8	8.5
Cell 6	641525	3581599	1134	NA	NA	NA	0.025	15.5	294	15.8	8.5
Cell 7	641528	3581588	1134	NA	NA	NA	0.025	15.5	294	15.8	8.5
Cell 8	641531	3581576	1134	NA	NA	NA	0.025	15.5	294	15.8	8.5
Cell 9	641534	3581565	1134	NA	NA	NA	0.025	15.5	294	15.8	8.5
Cell 10	641537	3581553	1134	NA	NA	NA	0.025	15.5	294	15.8	8.5
Cell 11	641540	3581542	1134	NA	NA	NA	0.025	15.5	294	15.8	8.5
Cell 12	641543	3581531	1134	NA	NA	NA	0.025	15.5	294	15.8	8.5

Source ID	UTM Easting (m)	UTM Northing (m)	Elevation (m)	NO_x (tpy)	CO (g/s)	SO_2 (g/s)	PM_{10} (g/s)	Stack Ht (m)	Temp (K)	Velocity (m/s)	Diameter (m)
South Cooling Tower Cell 1	641559	3581473	1134	NA	NA	NA	0.025	15.5	294	15.8	8.5
Cell 2	641562	3581462	1134	NA	NA	NA	0.025	15.5	294	15.8	8.5
Cell 3	641565	3581450	1134	NA	NA	NA	0.025	15.5	294	15.8	8.5
Cell 4	641568	3581439	1134	NA	NA	NA	0.025	15.5	294	15.8	8.5
Cell 5	641571	3581427	1134	NA	NA	NA	0.025	15.5	294	15.8	8.5
Cell 6	641574	3581415	1134	NA	NA	NA	0.025	15.5	294	15.8	8.5
Cell 7	641577	3581404	1134	NA	NA	NA	0.025	15.5	294	15.8	8.5
Cell 8	641580	3581392	1134	NA	NA	NA	0.025	15.5	294	15.8	8.5
Cell 9	641583	3581381	1134	NA	NA	NA	0.025	15.5	294	15.8	8.5
Cell 10	641586	3581369	1134	NA	NA	NA	0.052	15.5	294	15.8	8.5
Cell 11	641589	3581358	1134	NA	NA	NA	0.052	15.5	294	15.8	8.5
Cell 12	641593	3581346	1134	NA	NA	NA	0.052	15.5	294	15.8	8.5

[a] Effective diameter, treated as a horizontal release due to rain cover.

* CO emissions were modeled with worst case start-up emissions of 250 lbs/hr to assure compliance. CO emissions for normal operating conditions are estimated to be no more than 17.4 lbs/hr per stack.

UTM = Universal Transverse Mercator

NA = Not Applicable

e. Meteorological Data

Onsite meteorological data was collected for the period March 25, 2000, through March 24, 2001. This data set had a valid recovery rate of approximately 100%, and was approved as an representative on-site data set for regulatory modeling purposes.

f. Downwash and Good Engineering Practice (GEP)

EPA's BPIP program was used to calculate the building downwash parameters for input to ISCST3. All the facility stacks are subject to downwash. The building locations and GEP analysis were independently confirmed. All stacks are below the minimum 65 meter allowable GEP height, therefore all stack heights are fully creditable.

g. Background Concentrations

The background air quality concentrations were provided by ADEQ, and are derived from several nearby monitoring locations during the years 1998-2000. These concentrations are listed in Table 16.

3. Modeling Results

a. Significant Impact Modeling and SIA

The applicant demonstrated that none of the criteria pollutants had predicted maximum concentrations greater than the SIL for any of the relevant averaging periods. Table 17 presents results from the significant impact analysis. The maximum amount of a SIL was 4.85, or 97% of the PM_{10} 24-hour average SIL of 5 micrograms per cubic meter ($\mu g/m^3$). Therefore, a full impact analysis was not required for any of the criteria pollutants.

Table 16. Ambient Background Air Quality Data

Pollutant	Averaging Period	Background Concentration ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)
PM_{10}	24-hour	44	150
	Annual	15	50
CO	1-hour	570	40,000
	8-hour	570	10,000
SO_2	3-hour	42	1300
	24-hour	21	365
	Annual	6	80
NO_x	Annual	4	100

Table 17. Maximum Air Quality Impacts from Bowie Power Station Sources

Pollutant	Averaging Period	Maximum Project Impact ($\mu g/m^3$)	Location UTM Easting (m)	Location UTM Northing (m)	Distance from Bowie Power (meters)	Significant Impact Level ($\mu g/m^3$)	Maximum Distance of SIA (meters)
NO_2	Annual	0.88	641289	3581616	174	1	NA
CO	1-hour	391	635225	3583350	6444	2000	NA
	8-hour	203	641275	3581750	187	500	NA
SO_2	3-hour	14.4	641289	3581616	174	25	NA
	24-hour	1. 81	635125	3583500	6581	5	NA
	Annual	0.1	635175	3583350	6493	1	NA
PM_{10}	24-hour	4.85	635125	3583500	6581	5	NA
	Annual	0.3	635175	3583350	6493	1	NA
Lead	Quarterly	0.00002	641289	3581616	6493	--	NA

b. Comparison with AAAQGs

Modeling was performed to determine if the source would exceed the AAAQGs for air toxics of concern. The applicant modeled emissions of these air toxics. This modeling used the same dispersion model (ISCST3), meteorological data, building downwash, and basic model parameters and assumptions used in the criteria pollutant modeling. Concentrations were modeled for the process area and ambient air, according to Department policy.

Table 18 presents the results of both short term and the annual AAAQG analysis. The modeling demonstrates that maximum predicted concentrations of all air toxics are less than the AAAQG values. The maximum annual impact is for arsenic, with impacts at 30% of the AAAQG. The maximum short term impact is for the 1-hour ammonia concentration, at 15% of the AAAQG.

B. Additional Impacts Analysis

1. Growth Analysis

The applicant proposes that approximately 37 permanent new positions will be needed for operation of the new facility. Therefore, the potential of additional industrial, commercial, and residential growth from this facility will be limited.

Increases in air emissions from this population influx are primarily a result of the increase in vehicle exhaust from the limited increase in traffic flow. The existing traffic flow on I-10 will not be significantly affected by this change. Therefore, the applicant estimates that no significant growth-related air quality impacts will occur. The Department concurs.

2. Soils and Vegetation Impacts Analysis

A.C. R18-2-407.I.1 requires that the PSD permit application include an analysis of the impacts that emissions from proposed facility and from secondary growth will have on soils and vegetation. The applicant was unable to identify any specific sensitive soil and vegetation resources in the project vicinity. If the maximum predicted concentrations are compared to the screening levels found in the EPA document, "A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals," EPA 1980), none of the screening levels are remotely approached in magnitude. Therefore, the results indicate that the project will not adversely impact soils and vegetation in the area.

Table 18. Bowie Power Project Comparison to AAAQG for Compounds with Significant Emissions

HAP	Averaging Time	AAAQG ($\mu g/m^3$)	Emission Rate(lb/hr)	Emission Rate (tons/yr)	Predicted Max. Concentration	Percent of AAAQG
Acetaldehyde	1-hour	630	0.3	NA	0.224	0.04%
	24-hour	170	0.3	NA	0.026	0.02%
	Annual	0.45	NA	0.4	0.0003	0.07%
Acrolein	1-hour	6.3	0.04	NA	0.016	0.3%
	24-hour	2	0.04	NA	0.0026	0.1%
Ammonia	1-hour	230	92.0	NA	34.5	15.0%
	24-hour	140	92.0	NA	5.52	3.9%
Antimony	1-hour	15	0.003	NA	0.0034	0.02%
	24-hour	0.4	0.003	NA	0.0009	0.2%
Arsenic	1-hour	0.28	0.003	NA	0.0034	1.2%
	24-hour	0.073	0.003	NA	0.0009	1.2%
	Annual	0.0002	NA	0.013	0.00006	30%
Barium	1-hour	15	0.01	NA	0.014	0.09%
	24-hour	4	0.01	NA	0.002	0.05%
Benzene	1-hour	630	0.1	NA	0.317	0.05%
	24-hour	51	0.1	NA	0.112	0.22%
	Annual	0.14	NA	0.123	.0002	0.14%
Benzo(a) Athro	1-hour	0.79	0.00002	NA	0.0005	0.06%
	24-hour	0.21	0.00002	NA	0.00009	0.04%
	Annual	.00057	NA	1.0e-06	0.000	0.00%
Beryllium	1-hour	0.06	0.00007	NA	0.00008	0.13%
	24-hour	0.016	0.00007	NA	0.00002	0.13%
	Annual	0.0005	NA	0.0003	0.0000	0.00%
Cadmium	1-hour	1.7	0.002	NA	0.0034	0.2%
	24-hour	0.11	0.002	NA	0.00044	0.4%
	Annual	0.00029	NA	0.0036	0.00000	0.00%
Chloroform	1-hour	60	0.4	NA	0.427	0.7%
	24-hour	16	0.4	NA	0.116	0.73%
	Annual	0.043	NA	1.6	0.007	16.3%
Chromium	1-hour	11	0.003	NA	0.0043	0.04%
	24-hour	3.8	0.003	NA	0.0006	0.02%
Dichlorobenzene	1-hour	250	0.001	NA	0.0037	0.00%
	24-hour	66	0.001	NA	0.0005	0.00%
	Annual	0.18	NA	0.0011	0.0000	0.00%
Ethylbenzene	1-hour	4500	0.2	NA	0.081	0.00%
	24-hour	3500	0.2	NA	0.013	0.00%
Formaldehyde	1-hour	20	4.8	NA	1.79	8.95%
	24-hour	12	4.8	NA	0.292	2.43%
	Annual	0.08	NA	7.2	0.006	7.5%

HAP	Averaging Time	AAAQG ($\mu g/m^3$)	Emission Rate(lb/hr)	Emission Rate (tons/yr)	Predicted Max. Concentration	Percent of AAAQG
Hexane	1-hour	5300	1	NA	5.55	0.10%
	24-hour	1400	1	NA	0.715	0.05%
Iron	1-hour	22.5	0.001	NA	0.0013	0.01%
	24-hour	7.5	0.001	NA	0.0003	0.04%
Manganese	1-hour	25	0.007	NA	0.0012	0.00%
	24-hour	8	0.007	NA	0.00015	0.00%
Mercury	1-hour	1.5	0.001	NA	0.0009	0.06%
	24-hour	0.4	0.001	NA	0.0003	0.08%
Naphthalene	1-hour	630	1.17E-04	NA	.053	0.01%
	24-hour	400	1.17E-04	NA	0.002	0.00%
Nickel	1-hour	5.7	0.006	NA	0.0065	0.11%
	24-hour	1.5	0.006	NA	0.0011	0.07%
	Annual	0.004	NA	0.019	0.00006	1.5%
Propane	24-hour	14000	0.9	NA	0.636	0.00%
Selenium	1-hour	6	0.0007	NA	0.0008	0.01%
	24-hour	1.67	0.0007	NA	0.0002	0.01%
Silver	1-hour	0.3	0.02	NA	0.0185	6.2%
	24-hour	0.079	0.02	NA	0.0050	6.3%
Thallium	1-hour	3	0.003	NA	0.0034	0.1%
	24-hour	0.79	0.003	NA	0.0009	0.1%
Toluene	1-hour	4700	0.9	NA	0.3309	0.01%
	24-hour	3000	0.9	NA	0.0585	0.00%
Vanadium	1-hour	1.5	0.005	NA	0.0071	0.5%
	24-hour	0.4	0.005	NA	0.0009	0.2%
Xylene	1-hour	5500	0.4	NA	0.1631	0.00%
	24-hour	3500	0.4	NA	0.0301	0.00%

NA = Not Applicable

3. Visibility Impacts Analysis

A.A.C. R18-2-407.I.1 and R18-2-410 require that the PSD permit application include an analysis of the impacts that emissions from proposed facility and from secondary growth will have on visibility. This requirement is separate from any Class I visibility impact analysis. The visibility analysis was conducted for two Class II vistas from the town of Bowie, towards Fisher Hills to the northwest, and the Dos Cabezas Mountains to the southwest. Level 1 Visibility Screening methodology utilizing the VISCREEN model resulted in values higher than desired. Therefore, a refined visibility screening analyses using the PLUVUE II model was done. These results were satisfactory for a Class II Visibility analyses.

4. Class I Area Impacts Analysis

Air Quality impact analyses were done for four separate Class I wilderness areas located within 100 kilometers of the proposed facility. These wilderness areas are: the Chiricahua National Monument, the Chiricahua Wilderness Area, the Galiuro Wilderness Area, and the Saguaro National Park East Unit. All maximum predicted impacts from criteria pollutants, as listed in Table 19 below, are below the relevant threshold values. The ISCST3 model was used to predict maximum impacts for the Chiricahua NM because it is located within 50 kilometers of the proposed project. The CALPUFF model was used for those areas located greater in distance than 50 kilometers, the Galiuro WA and Saguaro NP. Since Chiricahua WA has locations both less than and greater than 50 kilometers, both models were used to predict maximum impacts. The Federal Land Manager (FLM) will provide final comments on the Class I analysis during the public comment period.

Table 19. PSD Class I Increment Analysis

Pollutant	Averaging Period	SIL	Chiricahua NM	Chiricahua WA	Galiuro WA	Saguaro NP
NO_x	Annual	NA	0.013	0.012	0.010	0.002
SO_2	3-hour	NA	0.12	0.49	0.40	0.33
	24-hour	1	0.05	0.16	0.11	0.082
	Annual	NA	0.004	0.006	0.005	0.002
PM_{10}	24-hour	1	0.13	0.40	0.31	0.23
	Annual	NA	0.012	0.16	0.015	0.005

NA = Not Applicable

Class I Visibility analyses was also done for the above five Class I wilderness areas. Guidelines for these analyses are based upon the Federal Land Manager's (FLM) Air Quality Related Values Workgroup (FLAG) Report, (December, 2000). The FLAG report defines impacts as the amount of predicted change in light extinction relative to natural conditions. A change in conditions of less than 5% from a single source is generally considered to be a slight impact where issuance of a permit is acceptable without any additional analyses. If the change is between 5% and 10% , then the change is assessed on a case by case basis, and further analyses may be required by the FLM. A change greater than 10% from a single source is likely to seen as an unacceptable impact. Impacts were all less than 5% for Saguaro NP and Galiuro Wilderness Area. For the Chiricahua Wilderness Area, one impact of greater than 5% (5.4%) occurred during the 5 years of modeled predictions.

Because the Chiricahua NM Class I area is within 50 kilometers of the proposed facility, the PLUVUE model was used for assessing impacts. Based upon guidance from FLAG, a threshold value is defined as a delta E of 1.0 and plume contrast of 0.02. The applicant's analyses showed results less than these levels. Again, the FLM will provide comments on the Class I analysis during the public comment period.

IX. INSIGNIFICANT ACTIVITIES

No.	POTENTIAL EMISSION POINTS CLASSIFIED AS "INSIGNIFICANT ACTIVITIES" PURSUANT TO A.A.C. R18-2-101.54
1	Landscaping, building maintenance, janitorial activities
2	Building Air Conditioning Units, including portable air conditioning units and the exhaust vents from air conditioning equipment
3	Turbine Compartment Ventilation Exhaust Vents
4	Sanitary Sewer Vents
5	Compressed Air Systems
6	Turbine Lube Oil Vapor Extractors and Lube Oil Mist Eliminator Vents
7	Steam Drum Safety Relief Valve Vents
8	Fuel Storage Tank for Emergency Diesel Fire Pump and Emergency Generator
9	Sulfuric Acid Storage Tank Vents
10	Various Steam Release Vents
11	Welding Equipment
12	Lab Hood Vents
13	Water Wash System Storage Tank Vents
14	Neutralization Basin
15	Sodium Hypochlorite Storage Tank
16	Hydrazine Storage Tank Vent
17	Fuel Purge Vents
18	Oil/Water Separator Waste Oil Collection Tank Vents
19	Sodium Hydroxide Storage Tank Vent
20	Condenser Vacuum Pump Vents

X. LIST OF ABBREVIATIONS

AAAQG .... Arizona Ambient Air Quality Guideline
A.A.C. .... Arizona Administrative Code
ADEQ .... Arizona Department of Environmental Quality
AQRV .... Air Quality Related Value
BACT .... Best Available Control Technology
BLM .... Bureau of Land Management
CAM .... Continuous Assurance Monitoring
CEMS .... Continuous Emission Monitoring System
CFR .... Code of Federal Regulations
CMS .... Continuous Monitoring System
CO .... Carbon Monoxide
CO_2 .... Carbon Dioxide
CTG .... Combustion Turbine Generator
DEM .... Digital Elevation Model
DLN .... Dry Low-NO_x
dscf .... Dry Standard Cubic Foot
EPA .... Environmental Protection Agency
^oF .... Degrees Fahrenheit
FERC .... Federal Energy Regulatory Commission
FLM .... Federal Land Manager
FLAG .... FLM Air Quality Related Values Workgroup
g .... gram
GEP .... Good Engineering Practice
H_2 .... Hydrogen
H_2O .... Water
HHV .... Higher Heating Value
hr .... hour
HRSG .... Heat Recovery Steam Generator
hp .... Horsepower
ISCST3 .... Industrial Source Complex Short Term Model
ISO .... International Standard Operation
lb .... Pound
lb/hr .... Pound per Hour
mg/m^3 .... Microgram per Cubic Meter
low-NO_x .... Low Nitrogen Oxide
K .... Kelvin
K .... Kelvin
m .... meter
MMBtu .... Million British Thermal Units
MMBtu/hr .... Million British Thermal Units per Hour
MW .... Megawatt
N/A .... Not Applicable
NA .... Not Available
NG .... Not Given
NAAQS .... National Ambient Air Quality Standard
N_2 .... Nitrogen
NH_3 .... Ammonia

NO .... Nitrogen Oxide
NO_x .... Nitrogen Oxides
NO_2 .... Nitrogen Dioxide
NPS .... National Park Service
NSPS .... New Source Performance Standard
NSR .... New Source Review
O_2 .... Oxygen
O_3 .... Ozone
Pb .... Lead
PM .... Particulate Matter
PM_{10} .... Particulate Matter Nominally less than 10 Micrometers
ppm .... Parts per Million
ppmv .... Parts per Million Volume
ppmvd .... Parts per Million by Dry Volume
PSD .... Prevention of Significant Deterioration
PTE .... Potential-to-Emit
RATA .... Relative Accuracy Test Audit
RBLC .... RACT/BACT/LAER Clearinghouse
S .... Sulfur
SCR .... Selective Catalytic Reduction
SIA .... Significant Impact Area
SIL .... Significant Impact Level
SNCR .... Selective Non-Catalytic Reduction
SO_2 .... Sulfur Dioxide
SO_3 .... Sulfur Trioxide
STG .... Steam Turbine Generator
TDS .... Total Dissolved Solids
TPY .... Ton per Year
TSP .... Total Suspended Particulates
USGS .... United States Geological Services
UTM .... Universal Transverse Mercator
UTME .... Universal Transverse Mercator Easting
UTMN .... Universal Transverse Mercator Northing
VOC .... Volatile Organic Compound
yr .... year